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# DRAFT ENVIRONMENTAL IMPACT STATEMENT (DEIS) FOR THE CUMULATIVE PRODUCTION/CONSUMPTION EFFECTS OF THE CRUDE OIL PRICE INCENTIVE RULEMAKINGS

DES 77-7

COMPLETED
ORIGINAL

Federal Energy
Administration

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# DRAFT ENVIRONMENTAL IMPACT STATEMENT (DEIS) FOR THE CUMULATIVE PRODUCTION/CONSUMPTION EFFECTS OF THE CRUDE OIL PRICE INCENTIVE RULEMAKINGS

DES 77-7

## EIS SUMMARY

Statement Type: (X) Draft ( ) Final Environmental Statement

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Office of Price Regulations
Federal Energy Administration
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1. Type of Action ( ) Legislative (X) Administrative

2. Brief Description of the Proposed Action

The Federal Energy Administration is implementing a new set of price regulations which, pursuant to the Energy Policy and Conservation Act (EPCA) and the Energy Conservation and Production Act (ECPA), is intended to ameliorate the impact of inflation and provide additional price incentives for crude oil production.

Execution of the EPCA is to be a three stage process. A two tier domestic oil pricing system was adopted to implement the mandated EPCA Stage I in February 1976. This Environmental Impact Statement analyzes the effect of Stage II of the EPCA crude oil price regulations. The proposed regulations provide for monthly upward adjustments of the compositie price, beginning in March 1976, to take into account the effects of inflation and to provide additional production incentives. It also analyzes the effect of the ECPA, which exempted stripper well oil from price controls and provides for special price treatment for heavy gravity crude oil produced in California and Alaska.

Stage III regulations which will provide special price incentives for tertiary oil recovery operations and other high-risk, high-cost productions, are presently being developed.

3. Summary of Environmental Impacts and Adverse Environmental Effects

(1) The cumulative effects of price incentives upon crude oil production provided by all of the price regulations pursuant to EPCA and ECPA will be small. The production in 1979 under any of the pricing options is estimated to be 6.5% to 9.5% greater than that of the base case. (In the base case prices

are rolled back and held constant at the point at which the weighted average price of all domestic crude oil is $7.66 per barrel at the real dollar value of February 1, 1976.) The impact on 1985 production due to any of the pricing options will be negligible, given that current price controls will elapse in May 1979. On the other hand, the cumulative effects of different pricing options on demand will be small in 1979 and negligible in 1985. The net impact on demand, it is estimated, will be between 11.7% and 12.9% in 1979 for different pricing options in comparison with the base case. In evaluating the cumulative environmental impacts associated with incremental production under the various pricing scenarios, it should be recognized that FEA's production figures may vary from actual incremental production. Because actual incremental production could be lower than FEA has projected, the environmental impacts associated with that production may be smaller than anticipated.

(2) In general, the environmental impacts associated with the incremental crude oil production and consumption resulting from the pricing policies pursuant to the EPCA and ECPA will not be significant. Nevertheless, the impacts may cause some concern in a few localities. The potential impacts include increasing consumption of fresh-water supplies, pollution of the lower atmosphere as a side effect of thermal recovery processes, accidental contamination of groundwater and surface water at production sites, scenic despoilment, and possible contamination resulting from oil spills in offshore oil production regions.

(3) In general, higher prices will reduce the demand for petroleum products which will lower the requirements for petroleum imports. In turn, the likelihood of oil spills from tankers at sea or in coastal waters will be reduced.

(4) Low levels of fugitive hydrocarbon emissions from oil handling processes may be experienced at production sites. Though appropriate control measures and good housekeeping practices can help to eliminate most of the hydrocarbon emissions, the possibility of some accidental leakage through valves, gaskets, seals, etc. cannot be entirely avoided.

(5) The steam injection process requires large quantities of fresh water, especially in such water deficient producing regions as California and West Texas. The need for fresh water may exert, on a local basis, some minor strain on fresh water resources.

## 4. Alternatives

- Taking no action.
- Stage II Implementation of EPCA only -- composite price of crude oil is escalated 10% per year:
  - Increase both upper-tier and lower-tier price at the same rate (Alternative IIA).
  - Hold lower tier price at constant real dollar level (Alternative IIB).
  - Hold lower tier price at constant nominal dollar level (Alternative IIC).
- Stage II and Stage III Implementation of ECPA simultaneously.
  - Alternative IIA plus one of the following alternatives for Stage III implementation:
    - Permit the tertiary production to be sold at the world market price (Alternative IIIA).
    - Permit the entire production involving tertiary projects to be sold at the world market price (Alternative IIIB).
    - Extend the stripper definition to include deep onshore and offshore wells (Alternative IIIC).
    - Eliminate the price penalty on California heavy gravity crude oil (Alternative IIID).
  - Alternative IIB plus Alternative IIIA
  - Alternative IIB plus Alternative IIIB
  - Alternative IIB plus Alternative IIIC
  - Alternative IIB plus Alternative IIID
  - Alternative IIC plus Alternative IIIA
  - Alternative IIC plus Alternative IIIB
  - Alternative IIC plus Alternative IIIC
  - Alternative IIC plus Alternative IIID
  - Alternative IIC plus Alternatives IIIA, IIIC, IIID

- Allow the crude oil price to be decontrolled immediately.

- Institutional encouragement of enhanced oil recovery operations.

- Speed-up of federal land lease schedules for petroleum exploration and production.

5. Comments on the Draft EIS are being requested from the following:

(1) Federal Agencies

Department of the Army
Department of Commerce
Department of Labor
General Accounting Office
Department of Defense
Department of Housing and Urban Development
Environmental Protection Agency
Federal Power Commission
Department of Agriculture
Department of State
Department of the Treasury
Nuclear Regulatory Commission
Tennessee Valley Authority
National Science Foundation
Energy Research and Development Administration
Interstate Commerce Commission
Council on Environmental Quality
FEA Regional Administrators I-X
Department of Health, Education and Welfare
Department of Interior
Department of Transportation
National Science Foundation
Bonneville Power Administration
United States Coast and Geodetic Survey
Library of Congress
General Accounting Office
Congressional Budget Office

(2) State Clearinghouses

All States
Virgin Islands
Puerto Rico
District of Columbia

## 3. Other Parties

League of Women Voters
National Urban League, Inc.
American Institute of Chemical Engineers
American Institute of Architects
Ford Foundation
Rockefeller Foundation
National Academy of Sciences
National Academy of Public Administration
National Academy of Engineering
American Society of Planning Officials
Consumer Federation of America
Environmental Defense Fund
Friends of the Earth
Izaak Walton League of America
National Association of Counties
National League of Cities
National Wildlife Federation
Sierra Club
U.S. Conference of Mayors
Institute of Gas Technology
Interstate Natural Gas Association of America
American Petroleum Institute
American Gas Association, Inc.
Independent Petroleum Association of America
California Independent Producers Association
Gulf Oil Corporation
Cities Service Company
Continental Oil Company
Ashland Oil, Inc.
Atlantic Richfield Company
Pennzoil Company
Phillips Petroleum Company
Monsanto Company
National Petroleum Council
Kerr-McGee Corporation
Getty Oil Corporation
Exxon Corporation
Mobil Oil Corporation
Texaco Oil Company
Standard Oil of California
Standard Oil of Indiana
Standard Oil of Ohio
Sun Oil Company, Inc.
Superior Oil Company, Inc.
Tenneco, Inc.
Union Oil of California
Shell Oil Company
Skelly Oil Company
Amoco Production Company
Marathon Oil Company
Society of Petroleum Engineers
American Association of Petroleum Geologists
Society of Exploration Geologists

This draft Environmental Impact Statement was made available to the Council on Environmental Quality and the public on 8-26-77.

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# GUIDE TO THE REPORT

The "project" examined in this study covers the full range of oil production technologies (present as well as anticipated); and the "environment" it affects is the entire United States. A variety of potential oil pricing policies are analyzed, moreover, for their impacts on production and consumption. The scope of the study, therefore, is quite extensive. We have tried to limit the scope and depth of analysis in areas of marginal interest, but credibility and completeness nevertheless demand that many topics be developed in considerable detail. Since most readers will not wish to explore each area discussed, the following chapter summaries are offered as aids to selection.

CHAPTER I provides a general overview of the pricing program and its goals. The legislative background is discussed, and the actions taken thus far under the Energy Policy and Conservation Act are reviewed.

CHAPTER II defines the spectrum of alternative Stage II and Stage III pricing policies under consideration by the FEA. These are the basic options that are then analyzed throughout the report.

CHAPTER III discusses methodology. The assumptions and data base -- with regard to production technologies and production potentials -- are made explicit; and the analytical procedures, parameters and constraints for assessing impacts -- both energy and environmental -- are described.

CHAPTER IV is a discussion of the various oil production technologies and their side-effects. Conventional recovery methods, both land-based and offshore, are reviewed; and the various types of tertiary recovery, together with profiles of their typical operations, are described in detail. The major environmental impacts of oil production, as well as ways of dealing with them, are extensively treated.

CHAPTER V and Appendix J describe the existing environment -- on national, regional, and sub-regional levels. Chapter V contains the highlights and principal features. The details are contained in the appendix. Because pricing actions are not specific to a single site, but rather apply to the whole country, the national and regional descriptions are necessarily overviews. They summarize data on air quality, water supply and quality, regional ecosystems, and socioeconomic activity. In addition, detailed environmental analyses are carried out for those regions that have figured, or are anticipated to figure, prominently in United States crude oil production.

CHAPTER VI estimates the effects of each pricing action on the regional production and consumption of petroleum products.

CHAPTER VII describes and compares the environmental impact of each of the pricing actions.

CHAPTER VIII suggests control procedures for reducing, and possibly eliminating, some of the adverse environmental impacts associated with oil recovery.

CHAPTER IX describes those adverse environmental impacts that simply cannot be avoided.

CHAPTER X analyzes two kinds of alternatives to the pricing actions: other policies that may stimulate increased domestic production of crude oil; and policies that aim not to increase domestic production, but which instead try to assure an adequate energy supply by other means.

CHAPTER XI identifies the resources that would be irreversibly and irretrievably committed to the pricing actions.

CHAPTER XII describes the various short-term, and not so short-term, environmental disruptions that often accompany oil production.

CHAPTER XIII discusses the benefits that presumably offset whatever environmental disruptions may occur. It examines, as well, the assumptions that underlie these alleged benefits, and it suggests some refinements.

# CHAPTER I

## BACKGROUND AND DESCRIPTION OF THE PROPOSED ACTION

### A. Introduction

On December 22, 1975, and August 14, 1976, the Energy Policy and Conservation Act (PL 94-163, "EPCA") and the Energy Conservation and Production Act (PL 94-385, "ECPA") were enacted into law. One of the stated purposes of the EPCA is to increase the supply of crude oil in the United States through price incentives and production requirements. To this end, Title IV, Section 401 of the EPCA amends the Emergency Petroleum Allocation Act of 1973 (PL 93-159, "EPAA") by adding to the end of the EPAA a new Section 8, which requires the President to implement an oil pricing policy which is both administratively feasible and consistent with the goal of obtaining optimum production of crude oil in the United States. The ECPA then amended this section and provided additional flexibility and price incentives for specific categories of domestic crude oil productions.

The EPAA, enacted during the Arab Oil Embargo, required price controls along with mandatory allocation authority so as to prevent price discrimination which would result from shortages. It required that the President, in exercising this authority, administer an equitable balance between two sometimes conflicting needs: the need to provide adequate inducement for the production of domestic crude oil, and the need to hold down spiraling consumer costs.

The EPAA contemplated that the Phase IV price controls established by the Cost of Living Council under authority of the Economic Stabilization Act would continue in effect until modified. Provision was made for a dollar-for-dollar passthrough of increases in the cost of crude oil and refined petroleum products to all marketers or distributors through the retail level. An important element in the initial Cost of Living Council price regulations was a two-tier pricing system for crude oil. A description of the crude oil price regulations promulgated by the Cost of Living Council and by FEO/FEA under the EPAA will be presented in the next section of this chapter.

The EPCA, enacted on December 22, 1975, amended the EPAA to require the establishment of a domestic crude oil "composite" ceiling price (maximum weighted average price) of $7.66 per barrel for the first sale in February 1976 and to initiate a forty-month program of continued controls on crude oil prices with a gradual escalation allowance. The President was also authorized to increase the composite price to:

1. account for inflation, as measured by the most recent first revision of the adjusted GNP deflator, and thereby maintain the composite price in real dollar terms, and;

2. provide additional price incentives to increase domestic crude oil production.

Limitations were also imposed on this authority. They included:

1. a three-percent limitation on the production incentive, and;

2. a ten-percent total limitation on the combined inflation adjustment and production incentive provisions.

The EPCA also established a procedure whereby the President was authorized to propose to the Congress that adjustments to the composite price in excess of three percent and/or ten percent limits be permitted for the high cost and high-risk crude oil productions. If neither House of Congress disapproved such a proposal within a 15-day Congressional review period, the President could implement the proposal.

The Energy Conservation and Production Act (ECPA), enacted August 14, 1976, exempted stripper well production from price controls and specified the method of imputing stripper oil prices and included stripper well production in the calculation of the composite price. The President was authorized to implement special price regulations that would provide a fair treatment for heavy gravity crude oil produced on the West Coast and Alaska and to stimulate domestic crude oil production by enhanced oil recovery operations. The ECPA also provided the President with the authority to escalate the composite price at a full ten percent per year, while eliminating the three (3) percent limitation for production incentives. Accordingly, the three-percent limitation on production incentive adjustments of the EPCA was removed, provisions were made for the exemption of stripper well crude oil production and the correction of gravity differential problems in the current price mechanism were made by the Federal Energy Administration in 1976.

## B. Goals of the Pricing Regulation Program in pursuant to EPCA and ECPA

Section 4(b)(1) of the EPAA requires that the crude oil pricing policy shall provide for preservation of an economically sound and competitive petroleum industry with a minimization of economic distortion, inflexibility, and unnecessary interference with market mechanisms. Section 8(b)(1)(A), as amended, requires that the pricing policy adopted be consistent with obtaining optimum production of crude oil in the United States. In order to meet these requirements, an attempt has been made to establish a pricing policy which would offer production incentives both for sustaining production from existing properties and for encouraging production from new properties while not generating any more inflationary pressure on the nation's economy.

Since there is a natural decline in the crude oil productive capacity from existing properties, the pricing policy adopted is designed to prevent the underutilization, or even premature abandonment, of these properties. This involves setting ceiling prices and classifications which (1) do not penalize the producer for this natural decline, and (2) encourage producers to use more advanced and costly techniques which would extend the productive life and increase the output of these properties. ECPA, by exempting stripper wells from price controls, is intended to encourage prolonged operation of wells which would otherwise have been abandoned as uneconomical under the price controls.

The nation's crude oil production prior to the Arab Oil Embargo of 1973-74 was mainly from those oil fields that have been fully developed. Since 1973, the costs of petroleum exploration and production have increased over 80%. Consequently, the extraction of crude oil from known, but as yet undeveloped, properties will be much more costly than extraction from existing oil fields. Additional costs will also accrue to those properties which require further exploration. Any pricing policy which allowed these costs to impede the production of crude oil from new oil fields would fail to optimize total domestic production.

For this reason, a policy has been adopted which is aimed at encouraging new production from existing oil fields as well as from such high cost and high risk properties as offshore sites and deep horizon wells. Provisions of the Energy Conservation and Production Act are also specifically directed towards stimulating the development of tertiary recovery projects, which may otherwise be unfeasible under some or all existing crude oil price control ceilings.

The dual purpose of maximizing production from existing properties and stimulating the development of new properties can only be achieved if producers are given, as early as possible, a firm level of the projected allowable prices for various classifications of crude oil for the duration of the 40-month price control program. While it is understood that these projections are subject to changes, it is the goal of the pricing regulation program in FEA to provide to producers the greatest possible degree of certainty with respect to future price levels of various classifications of domestic crude oil. Therefore, schedules of monthly price adjustments were first offered in March 1976 for the remaining months of the program. The purpose of these forecasts is to avoid undue delay and to encourage producers to make early decisions with respect to the use of enhanced recovery techniques and the development of new oil productions in high-cost and high-risk properties.

An additional goal of this pricing regulation program is to provide adequate adjustment for the effects of inflation. Ceiling prices set in such a way that inflation could erode the incentive provided by the series of price regulations could have an adverse impact on crude oil production. To avoid this, the EPCA allows, within certain limits, for ceiling price adjustments which are calculated to ameliorate the impact of inflation. The revisions made are to be based upon the most recent first revision of the adjusted Gross National Product (GNP) deflator, which is issued quarterly by the U.S. Department of Commerce. Under EPCA the adjustments were limited to the GNP deflator plus up to 3 percent per annum additional incentive, not to exceed 10 percent per annum overall. As amended by the ECPA, however, the 3 percent per annum additional incentive limit was dropped, allowing the full increment of 10 percent per annum.

## C. Previous Pricing Actions on U.S. Crude Oil Productions

### (1) CLC Regulations.

On August 17, 1973 the Phase IV price regulations applicable to the petroleum industry were issued by the Cost of Living Council (CLC). Declining domestic production since 1971 and sharp increases in price and volumes of imported oil on which the U.S. had become increasingly dependent contributed to the decision by CLC to control petroleum industry prices on the basis of specific regulations covering the entire petroleum industry rather than on the basis of the general price regulations then applicable only to a segment of the industry. The central element of CLC regulations was the two-tier pricing scheme which is described as follows.

Two-Tier Price System - The objectives of the two-tier pricing system were: (1) hold domestic petroleum prices below rapidly rising world price levels, and (2) provide sufficient price incentives for increased domestic crude oil production. The net effect, however, was to encourage additional shallow drilling into established reserves, which yielded a minimum amount of oil per unit of drilling and did not add appreciably to proven reserves.

The CLC two-tier system initially provided a ceiling price for "old" oil frozen at the May 15, 1973 posted price level plus 35 cents. The ceiling price for "new" and "released" crude oil was the market price. "Stripper well lease" crude oil was later (November 16, 1973) exempted from CLC regulations. "Old" crude oil was the volume of crude oil produced and sold from the property concerned in the same month of 1972 (the base production control level, or "BPCL"). "New" crude oil was the volume produced and sold each month in excess of the property's BPCL. Also, for every barrel of "new" crude oil produced and sold, the producer was permitted, as a further production incentive to "release" one barrel of "old" crude oil for sale at the market price ("released" oil).

The May 15, 1973, posted price was chosen as the base price for "old" crude oil because that date represented a time of relative stability in the crude oil market. The additional 35 cents per barrel was based on estimated average increases in posted prices between May 15, 1973, and August 19, 1973, the effective date of the CLC Phase IV petroleum regulations. An additional $1.00 per barrel was added to the "old" crude oil ceiling price in December, 1973 in order to narrow the gap between the lower ("old" crude oil) and upper ("new" and "released" crude oil) tier prices which had widened considerably during the Embargo due to dramatic increases in world prices.

### (2) EPAA Regulations

The EPAA directed the President to promulgate regulations to specify (or prescribe a manner for determining) the price of crude oil, residual fuel oil and refined petroleum products, and to provide for their equitable distribution at equitable prices. The EPAA provided for a dollar-for-dollar passthrough of net increases in the cost of crude oil, residual fuel oil and refined petroleum products. Pursuant to the EPAA, The Federal Energy Office (FEO) promulgated regulations designed to achieve these objectives. The initial Mandatory Petroleum Allocation and Price Regulations were issued and became effective on January 14, 1974. The CLC two-tier pricing system applicable to producers of crude oil was adopted by FEO with "old" crude oil subject to a ceiling price. "New" and "released" crude oil could be sold at market prices, and stripper well lease crude oil was exempt from controls. Crude oil supplier-purchaser relationships were frozen to provide equitable distribution of domestic crude oil.

Generally, refiners, resellers and retailers of petroleum products could charge a price which reflected the weighted average price at which the product was priced in transactions with the class of purchaser concerned on May 15, 1973, plus increased costs incurred since that time. To faciliate the implementation of EPAA price regulations, the following decisions were made:

Property definition - The amount of crude oil eligible for the "upper tier" or market price and the amount required to be sold at the "lower tier" ceiling price were calculated with respect to each "property". The CLC defined a "property" as the right which arises from a lease or from a fee interest to produce crude petroleum. This definition of property, which was subsequently adopted by FEO and FEA, was recently amended by FEA as discussed below.

"Base Production Control Level" - (BPCL) is basically the historic volume of crude oil produced and sold from a given property above which a producer must increase production levels in order to qualify current production as "new" or "upper tier" crude oil.

As defined by CLC, the BPCL for each property was the number of barrels produced and sold from the property in the corresponding month in 1972, or the number of barrels produced and sold in the year 1972 divided by 12, if crude oil was not produced and sold from that property in every month of 1972. This definition was adopted by FEO and FEA but was later redefined by FEA to permit 1975 to be used as an optional base year. Under the new definition, the monthly BPCL is the total annual production in either 1972 or 1975 divided by 366 or 365, respectively, and multiplied by the number of days in that particular month.

Pursuant to the requirements of the EPAA, CLC exempted production from stripper well leases under regulations which defined a stripper well lease as a property whose daily average production did not exceed 10 barrels per day per well during the preceeding calendar year. Once the production has been classified as stripper that classification will continue even if the daily production is increased above ten barrels per day later on.

(3) Crude Oil Entitlements - By the end of the Arab Oil Embargo of 1973-74, there was a five to six dollar price spread between "old" domestic crude oil and "new and released" domestic and imported crude oils. The average crude oil cost for refiners ranged from less than $5 a barrel to more than $11 a barrel, depending primarily on each refiner's mix of foreign, "old", "new", "released" and "stripper" oil.

This wide spread in crude oil costs resulted in product prices differing by as much as fifteen cents a gallon. Consumers were able to price shop, and high cost suppliers had to lower prices in order to sell their products. The competitive viability of the large independents and the many small refiners who were dependent on foreign or upper tier crudes was seriously threatened. Since regulations under the EPAA had to provide for "preservation of an economically sound and competitive petroleum industry ... and to preserve the competitive viability of independent refiners (and) small refiners", FEA determined that its regulatory program had to be modified.

Considering the potential effects of different options upon the refinery operations, large or small, in various locations, the proportionate allocation of old oil to all refiners was selected as the best mechanism to assure competitive viability of these refiners and the marketers they supply, while accomplishing the other requirements of mandatory allocation. The Old Oil Allocation Program was made effective in November 1974, and was later modified to account for the ceiling prices, effective February 1, 1976, on upper tier domestic crude oil provided for by the Energy Policy and Conservation Act, and the September 1, 1976 exemption of stripper well crude oil. This program is generally referred to as the "Entitlement Program," and is the key to maintaining competitive viability of refiners and marketers and providing for equitable prices to consumers under a multi-tier crude price structure. Though it was developed to offset certain undesirable effects of multi-tiered crude pricing, it has become the support structure for the system. The present multi-tiered price system, established by FEA to conform to the crude pricing requirements of the Energy Policy and Conservation Act, continues to rely on the Entitlements Program to assure competitive viability among petroleum refiners and marketers, while equitably distributing the benefits of price controlled domestic crude oil among all petroleum product users.

## D. Actions to be taken

### (1) EPCA Regulations

Pursuant to the EPAA, the President was authorized to implement special price and allocation regulations to minimize the adverse impacts of the shortage of crude oil resulting from the Arab Oil Embargo in 1973-74. It became apparent that, in order to assure a stabilized crude oil supply in the long run, increased domestic production had to be encouraged. Specific provisions were mandated by Section 401 of the EPCA to provide price incentives that would encourage domestic production while minimizing inflationary pressure which could inhibit economic recovery.

The stipulated requirements in EPCA, which were implemented and promulgated as FEA regulations, involved the implementation of a system of price controls applicable to all first sales of domestic crude oil. The system was designed to result in a statutorily mandated weighted average first sale price ("composite price") of $7.66 per barrel in February 1976. The EPCA also permitted upward adjustments in the composite price to reflect inflation plus not more than a 3 percent annual increase as a production incentive provided the sum of the two adjustments did not exceed 10 percent annually. In addition, the EPCA provided a mechanism for further adjustments in excess of the 3 percent and 10 percent limitations, if they were justified as a further production incentive. These further adjustments are subject to Congressional veto. Finally, the EPCA repealed the EPAA stripper well exemption. The expiration date of the crude oil pricing mandate under the EPCA is May 31, 1979.

(1.1) Stage I Implementation - Effective February 1, 1976, FEA implemented the mandated provisions as required in Section 401 of the EPCA by retaining the two-tier pricing system with the following price controls.

(1) Upper tier crude oil (formerly new, released and stripper crude oil) was controlled at an estimated average first sale price of $11.28 per barrel in February, 1976, by means of a $1.32 per barrel roll-back from the highest posted price at each field on Sept. 30, 1975 (See Federal Register, Vol. 41, No. 23, February 3, 1976).

(2) Lower-tier crude oil (formerly old crude oil) was controlled at an estimated average first sale price of $5.25 per barrel in February 1976. This price was based on the highest posted price at each field on May 15, 1973, plus $1.35 per barrel. (See Federal Register, Vol. 41, No. 23, February 3, 1976).

To help assure continued production incentives for the fields experiencing natural declines of production rates since 1972, a property's BPCL was redefined as either, at the election of the producer, the property's average monthly production and sale of old crude oil in 1972 or the 1975 daily average production times the number of days in the month. All existing cumulative deficiencies in production, which previously had to be made up before oil could be qualified as "new" oil, were eliminated, as was the released oil concept.

Under the revised definition, each property's BPCL for a particular month was allowed to be calculated on the basis of the property's total 1975 production and sale of old crude oil, divided by 365, and multiplied by the number of days in that month during 1975. Those whose BPCL's would be raised because they were eliminating large cumulative deficiencies during 1975 were given the option of using their new BPCL's. This new basis for calculating BPCL's differs from the previous system, which relied upon month-by-month tallies of 1972 production. It was determined that the new definition of BPCL avoided the anomalous or unrepresentative results of the other calculations. (Stage II of EPCA defines additional adjustments to BPCL's to account for natural declines in production.)

The new BPCL's, based upon 1975 production and sale of old crude oil, are obviously lower for properties where the 1975 production was below the 1972 production. They are also lower for properties which exceeded their BPCL's of 1972 and sold new crude oil in 1975. The reason for this is that under the former regulations, released crude oil, which would otherwise have been sold as old released crude oil, was sold at upper tier prices and would not be included in a property's production and sale of old crude oil during 1975. Overall, this system allows the FEA to take into account the natural decline rate associated with primary production, while encouraging each producer to optimize his crude oil output.

One additional change from the previous regulations was the elimination of the released crude oil provision, which had been introduced by the CLC as an incentive specifically appropriate to a short-term program. The 40-month EPCA pricing policy would allow crude oil produced in excess of the BPCL to be sold at the upper tier ceiling price, but no equivalent amount of lower tier crude oil would be released to be sold at upper tier prices.

(1.2) Stage II Implementation - "Stage II" of the EPCA implementation included the upward adjustments to the composite price. Section 401 of the EPCA (until later amended by the ECPA, as discussed below) permitted upward adjustments to reflect inflation and to provide for additional production incentives subject to the restrictions that the adjustment to provide a production incentive may not exceed 3 percent annually and the adjustment to reflect the impact of inflation must be based on the first revision of the most recent Implicit Price Deflator for the Gross National Product. The combined effect of both adjustments could not exceed a maximum of 10 percent annually. The Stage II Implementation was issued, on a tentative basis, on March 1, 1977 and will be subject to modifications based on the results of this EIS.

The statutory limit of 3 percent per year production incentive price adjustments applies to the composite price. FEA must therefore determine how to distribute the adjustment between the two tiers. Without the resolution of one further issue, the question of how to distribute price adjustments in Stage II would have been moot. Section 8(b)(2) specifies that positive production effects must be realized if the price of lower tier crude oil is to be adjusted upward. It was determined that the failure to allow these prices to increase would discourage the existing crude oil production. Hence, the decision was made to permit increases in lower tier ceiling prices.

It was recognized that the Stage I regulations might not offer adequate incentives to the producers of many existing properties, since the regulations did not take into account the natural decline in production from those properties. As a property falls further and further below its BPCL, there is an ever-diminishing likelihood that that property will ever be able to produce upper tier crude oil. Because of these concerns, a policy was adopted of adjusting BPCL's on the basis of annual average production decline between 1972 and 1975 on a property-by-property basis. Semiannual adjustments would be allowed for all properties which failed to produce new crude oil during the first 5 months of the pricing program, as well as for any property which, in any subsequent 6-month period, fails to produce crude oil in an amount at least equal to the sum of its monthly BPCL's for that period. This adjustment would not involve any change in a property's current cumulative deficiency. This provision for adjusting BPCL's would offer no additional incentives for those properties which, realistically, had no chance of producing upper tier crude oil. But a lack of incentives, coupled with the erosion of lower tier prices in real dollars, would reduce the total production of old crude oil. This, in turn, would further alter the ratio between old crude oil production and new crude oil production. (The proportion of new crude oil was already expected to rise, since the pricing policy was designed to encourage the production of this oil. It could be expected to rise even more with the downward adjustment of BPCL's.) As a result, a declining proportion of lower tier crude oil at an unchanging price would effectively hold down any upward price adjustments for upper tier crude oil.

These considerations led to the alternative approaches to distribution of the price adjustments between the two tiers. Distribution of all of the price adjustments to the upper tier was initially considered. The decision was made, however, to apply the scheduled monthly price adjustments equally, at least as long as the rate of inflation did not exceed the rate of adjustment to both tiers. At that point, preference would be given to the upper tier prices. In the case of the production incentive adjustment, analysis indicated that the entire 3 percent adjustment allowable would be needed to neutralize the impact which the changes in the production ratio would have on the composite price. In fact the adjustment proved insufficient and a price freeze was put into effect.

FEA is required (41 FR 15573, April 13, 1976), under the National Environmental Policy Act of 1969 (PL 91-190, NEPA), to determine whether or not the Stage II regulations would "significantly affect the quality of the human environment." An environmental impact assessment has been prepared which indicates that no adverse environmental impacts are likely in the short term, since the major immediate impact of the regulations was determined to be a slight increase in the price of crude oil, and an attendant slight decline in the use of petroleum products. This price increase would not prompt a switch to cheaper, more polluting fuels. Long-term effects, however, were not as easily determined. On the basis of the environmental assessment, it was concluded that an environmental impact statement (EIS) should be prepared to assess the long-term environmental effects of the Stage II regulations.

(1.3) Stage III Proposed Rulemaking - The purpose of the Stage III proposal was to consider whether additional incentives, beyond the adjustments adopted in the Stage II proceeding, were needed to maintain or increase production. If additional incentives were found to be necessary, such proposed amendments would then be forwarded to Congress for review. The need for additional incentives was considered in three areas: (1) incentives for discovery and development of high cost and high risk properties; (2) the application of enhanced recovery techniques; (3) sustaining production from marginal wells. Specific proposals for increased production incentives which were considered were the following:

- Upper tier or market level prices for all production from new reservoirs.
- Market level prices for production from new wildcat properties.
- Market level prices for production from new properties located on the Outer Continental Shelf.
- Market level prices for production from new deep wells or deep horizons in onshore properties.
- Market level prices for production properties operated by independent producers.
- Upper tier or market level prices for incremental production derived through application of certain high cost enhanced recovery techniques.

- Qualification of stripper well prices based on the preceding 12 months of production rather than the preceding calendar year.

- Qualification of stripper well prices according to well depth and according to onshore or offshore location.

- Qualification of stripper well prices according to the ratio of non-crude oil fluids produced.

- Qualification of marginal gas wells producing condensate for stripper well prices.

- Market level prices for stripper well production. Adjustments to historical gravity price differentials for heavy crude oil.

The Stage III proposal was deferred, in part, because of the increased pricing flexibility afforded by the elimination of the 3 percent production incentive limitation and the exemption of stripper well production from price controls by the Energy Conservation and Production Act (ECPA) enacted August 14, 1976. (See Section (D) below.)

As required under NEPA (41 FR 18877, May 7, 1976), an environmental impact assessment of the proposed Stage III regulations has been prepared. FEA has concluded, on the basis of the environmental assessment, that there would be no significant adverse short-term environmental effects from the proposed adjustments, since most of the activities which these adjustments would generate require long lead time. However, it was determined that this EIS would be prepared in order to examine in greater detail the longer-term environmental impacts of the proposed price adjustments resulting from the Stage III implementation.

Price Freeze - Because the estimated impact of the Stage I and Stage II implementation of EPCA was based on estimates of upper and lower tier volumes and prices, Stage II regulations provided that the crude pricing schedule would be adjusted when actual price and volume data became available. When the actual February and March 1976 data became available to FEA, they revealed that the Stage II adjustments were resulting in composite price overages and that the crude pricing schedule would have to be adjusted.

Based on actual production volumes and prices for the months of February and March, 1976, FEA estimated that revenues received by crude oil producers were approximately $60 million in excess of those which would have been received if the actual composite price for that period had concurred exactly with the statutory composite price in February and March, 1976.

It was determined that, rather than a roll-back, the best method would be to freeze prices effective July 1, 1976, initially for two months (July and August). This would give FEA an opportunity to receive and evaluate two additional months of actual volume and composite price data, before making further adjustments to the crude pricing schedule.

In January of 1977 the upper tier ceiling price was rolled back 20 cents per barrel for the months of January through March. In March the upper tier ceiling price was rolled back an additional 45 cents per barrel for the months of March through July.

(2) ECPA Regulations - On August 14, 1976 the ECPA was enacted. It contained several significant provisions regarding crude oil prices.

Removal of the 3-percent limitation - The ECPA removed the EPCA 3-percent limitation on the production incentive. The overall 10 percent annual limitation on price adjustments to reflect inflation and provide a production incentive remained. This greater flexibility was intended to provide FEA with a further means to encourage domestic production, with a high priority on development and application of high-cost enhanced recovery techniques, and compensation for certain large gravity price differentials associated with heavy crude oils from California and Alaska.

Stripper Exemption - The ECPA permitted stripper well crude oil once again to be sold at market price levels by removing the price limitations imposed on stripper well production by the EPCA. However, stripper well production and sales were not excluded from the calculation of the composite price. Rather, stripper oil was to be given an "imputed" price of $11.63 per barrel (plus the difference between the August 1976 weighted average price of other controlled crude oil productions and the weighted average price of other controlled crude oil production in the current month) for purposes of the monthly composite price calculation. It was later found that this price exceeded the actual EPCA stripper price by approximately 30 cents per barrel.

FEA implemented the mandated ECPA provisions with respect to stripper well properties by exempting crude oil produced from such properties from price controls effective September 1, 1976.

## Enhanced Oil Recovery Mandate

The ECPA identified two additional priorities with respect to optimizing domestic production: enhanced recovery techniques and the correction of the gravity differential problem. The FEA has issued a notice of proposed rulemaking to consider how high-cost enhanced recovery techniques can be identified and how price incentives can be applied to stimulate such domestic production. Two public hearings have been held to receive comments and responses from industry and consumer groups.

## Gravity Differential Price Adjustment

Effective October 1, 1976, the FEA acted in pursuant to ECPA to adjust gravity price differentials with respect to heavy California and Alaskan crude oil. Lower tier heavy California crude oil historically was priced substantially below the national average for the lower tier due to larger than average gravity price differentials existing on May 15, 1973. Nationally, on May 15, 1973, gravity price differentials for crude oil averaged between 2 and 2.5 cents per API degree per barrel, while in California the gravity price differentials averaged 6.2 cents per API degree per barrel.

Accordingly, the FEA amended the price rules to permit the ceiling price for lower tier California and Alaskan crude oil to be increased by 2 cents per degree per barrel for each degree API gravity between 34 degrees API gravity and 40 degrees API gravity that the crude oil being offered for sale is below 40 degrees API gravity, plus 3 cents for each degree API gravity that the crude oil being offered for sale is below 34 degrees API gravity. While this amendment increased the ceiling prices, it appears that actual sale prices were not affected significantly due to market forces.

Both of these priorities have also been part of the considerations in the Stage III implementation of EPCA. Thus, the environmental impacts resulting from these two price provisions would be included as part of the EIS for the Stage III implementation of EPCA.

### (3) Redefinition of Property

FEA issued clarifications necessary to resolve ambiguity in the meaning of a "right to produce" which had prevented the completion of many audits. As part of these clarifications, FEA concluded that the original property concept (see Section c (2) above) which followed a "premises described by a single oil and gas lease" concept without regard to the separate reservoirs which might underlie the premises, did not provide appropriate incentives under the longer term system of price controls mandated by EPCA. This was because increased production from one reservoir might fail to qualify as upper tier crude oil because of the requirement that total production from the property must exceed the BPCL and cumulative deficiency determined from all reservoirs which underlie the property.

Accordingly, the definition of property was amended, effective September 1, 1976, to permit a producer to treat as a separate property each separate producing reservoir subject to the same right to produce crude oil provided the reservoir is recognized as separate and distinct by the appropriate governmental regulatory authority. Although this change was not required in order to implement the EPCA or ECPA, it had been under consideration by FEA for some time and is noted here because it has some effect on volumes of lower tier and upper tier oil. The effect of the new definition is to increase the difficulty of relating upper tier production changes to the composite price limitation.

# CHAPTER II

# ALTERNATIVE PRICING ACTIONS

## A. Introduction

The Energy Policy and Conservation Act (EPCA) requires the President to establish oil pricing policies that will limit price increases for domestic oil to a legislated maximum rate while also implementing price incentives for the development of new reserves and production. The effects on production of seven different price control options were evaluated for this study. Alternative ways of dividing the allowable price increase between upper and lower price-controlled tiers were combined with incentives aimed at increasing the production of tertiary oil, or California low gravity oil, or oil from low-production-rate offshore wells. Production forecasts for each of the seven cases were prepared for 1979, the year that crude oil price controls are scheduled to lapse, and for 1985.

Some other price control options were considered for analysis. These include:

1. Free market price for new crude oil production in frontier areas. Transportation costs from frontier areas will be high. And all new crude oil production receives the upper tier price. It was concluded that controlled upper tier wellhead price for frontier oil would be close to free market delivered price less transportation. Any difference would be too small to have a significant effect on production in frontier areas in 1979.

2. Further revisions in the definitions of property, well counts, etc. These could be utilized to increase cash flow to lower tier producers. These options were not evaluated since there were no definitive plans in this regard.

In each case evaluated, production levels and prices were determined such that the statutory mid-1979 composite price was achieved. In all cases, production from stripper wells was included in the composite price calculation as if its price were upper tier. This treatment of stripper well production differs from that embodied in the ECPA amendments to the EPAA of 1973 which provide for a more complex formula for pricing stripper oil and for including that price in the determination of the actual weighted average first sale price for crude oil.[1] The simpler alternative used for price determination produces a result that is indistinguishable from that in the ECPA and considerably simplified the examination of the alternative pricing policies. Since the same section (Section 121) exempts stripper production from price regulations, its actual market price will match the free market price (delivered price of imports less transportation cost).

Alaska North Slope production was included at its estimated weighted average wellhead price. Because of high transportation costs, wellhead price in 1979 will be substantially below the allowable upper tier price. The estimated 1979 wellhead price turns out to be very close to the statutory composite price. Hence, the composite is not affected by whether North Slope oil is included or not. The significance of this fact is that North Slope oil could have been ignored in the evaluation of 1979 pricing effects without changing the production forecasts at all.

There follows detailed descriptions of the alternative price control options that were evaluated. Two kinds of prices are used in the case definitions. A "nominal" price is the price received at the time of a transaction; i.e., the price is denominated in current dollars. A "real" price includes the effect of inflation on the value of money; i.e., the price is denominated in terms of dollars of a specified purchasing power. In this study, "real" prices are stated in terms of dollars with the purchasing power that prevailed in 1975. It will be shown later that the statutory composite price for domestic crude oil in May of 1979 will be 10.44 nominal dollars per barrel which is equivalent to 8.50 real dollars per barrel.

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[1] Energy Conservation and Production Act (PL 94-385), Section 121.

## B. Base Case

In this case the average lower tier crude oil price is assumed to be fixed at the June 1976 average nominal price of $5.15 per barrel[1] throughout the 1976-1979 control period. The composite price is also required to remain constant at $7.66 per barrel throughout the period.[2] Consequently, the average upper tier price must be adjusted to permit the nominal composite price to remain constant. Stripper well production was treated as noted above in Section II.A.

In this case, only Alaskan North Slope crude is priced at the upper tier price. This is so because the upper tier price is less than the free market price less transportation.

This pricing option is considered the Base Case because, except for stripper wells, it provides no new price incentives whatsoever to stimulate production or investment. Indeed, to the extent that the real price of oil declines as a result of inflation, this case actually provides a disincentive relative to mid-1976 price levels. Further, due to physical depletion and recently implemented changes in property definitions, production classified as lower tier will decrease during the period. But upper tier plus stripper output is expected to increase. Consequently, the average upper tier nominal price would have to decrease during the period to maintain a constant nominal composite price.

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[1] Value received from Compliance Section on August 17, 1976; also published in Oil Daily (September 2, 1976): 1.

[2] Statutory price for February 1976, contained in the EPCA.

## C. Stage II Price Adjustments

The intent and background of Stage II pricing policy are discussed in detail in Section C.2.2 of Chapter 1. Briefly, the perceived need to provide price incentives to both upper and lower tier production led to a decision to distribute price adjustments equally between both tiers. However, it is possible that alternative distributions of the price adjustments would have less environmental impact than the equal distribution that was chosen.

There are, of course, an infinite number of formulae that could be developed to distribute the price incentive between the tiers. Two of these distributions were evaluated. These two were chosen so as to bracket the range of possible alternatives. At one extreme, all the incentive is to be given to the upper tier (by holding the nominal lower tier price at its February, 1976, value). At the other extreme, the lower tier real price is maintained throughout the control period. This option would lead to a higher lower tier price (and a lower upper tier price) than the equal distribution option.

The ECPA permits the nominal composite crude oil price to escalate at the rate of 10 percent per year compounded starting from the EPCA statutory value of $7.66 per barrel in February 1976. At the time the EPCA expires on May 31, 1979, the allowable nominal composite price will have increased to $10.44 per barrel.[1]

In this and all subsequent cases, Alaskan North Slope oil is given an average nominal wellhead price of $10.50 in 1979. This price was developed from a basic assumption that North Slope oil must be price competitive or no one will buy it. Because transportation cost for this oil will be so high, the competitive wellhead price is well below the upper tier price to which it otherwise would presumably be entitled. The competitive wellhead price was determined by assuming that the free market price for imported crude oil will increase

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[1] $\$7.66 \times (1.1)^{3.25} = \$10.44$ per barrel. The corresponding "real" price is $8.50 per barrel. This value is based on GNP deflator forecasts given in Data Resources, Inc., "Review for FEA," August 1976. The inflation rates are: 1976 -- 5.1 percent; 1977 -- 5.4 percent; 1978 -- 5.6 percent; and 1979 -- 5.0 percent. Consequently, the real price in 1979 corresponding to a nominal price of $10.44 is

$$\frac{\$10.44}{(1.051 \times 1.054 \times 1.056 \times 1.050)} = \frac{\$10.44}{1.228} = \$8.50.$$

at exactly the same rate as GNP prices, and that Alyeska Pipeline tariff plus ocean transportation will average $5.45.[2] Needless to say, North Slope price will be highly dependent on its ultimate destination which is still very much in doubt. A fortuitous result of the assumptions made here is that the North Slope 1979 average nominal price of $10.50 is so close to the statutory mid-1979 composite price of $10.44 that production estimates in every case would be the same whether North Slope crude is included in the composite computation or not.

Stripper well production is treated as noted in the introductory section (II.A).

Case IIA -- Equal Percent to Both Tiers

In this case, average lower tier and upper tier nominal prices are allowed to increase by equal annual percentages. This is the policy option that was adopted on April 8, 1976.[3] As mentioned previously, the fraction of upper tier oil in the composite will increase steadily throughout the period as lower tier production depletes. Consequently, if prices were held constant for both tiers, the composite price would rise. Hence, average nominal prices for both tiers in this case will increase at rates slower than the 10 percent per year permitted for the composite.

Case IIB -- Constant Lower Tier Real Price

In this case, the average lower tier nominal price is increasing by the rate of inflation so that the average lower tier real price is held constant. The average upper tier nominal price, then, is determined by the necessity to achieve a 10 percent per year increase in the composite nominal price.

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[2] Free market price in 1975 was $13.00. 13.00 x 1.228 = 15.96 nominal in 1979. Alyeska tariff in 1979 will be $3.1 per barrel. It was assumed that one million barrels per day (71 percent) of the oil would be transported to California at a cost of $1.5 per barrel, and the balance (29 percent) to the Gulf Coast at a cost of $4.5 per barrel. 15.96 - 5.45 = 10.50.

Tariff forecasts published subsequent to this work are sharply different from those used here. See, for example, New York Times, September 21, 1976, page 1, or Oil and Gas Journal, October 4, 1976, page 69. But the combined total transportation cost estimate is quite close to these later forecasts.

[3] Chapter I, Section C.2.2.

## Case IIC -- Constant Lower Tier Nominal Price

In this case, the average lower tier price is held constant throughout the control period at a nominal value of $5.15 per barrel, the actual level experienced in June, 1976. The real price, consequently, declines from $4.90[4] per barrel in mid-1976 to $4.19[5] per barrel in mid-1979. This price is the same that would be received by average lower tier oil in the Base Case. As would be expected, this option gives the highest upper tier price.

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[4] $\frac{5.15}{1.051} = 4.90$

[5] $\frac{5.15}{1.223} = 4.19$

## D. Stage III Price Incentives

The intent and background underlying proposed Stage III pricing policies are discussed in detail in Sections C.2.3 and C.2.4 of Chapter I. The authority for Stage III pricing alternatives derives from both EPCA and ECPA. Stage III incentives are designed to discriminate among classes of crude oil in favor of high cost classes such as frontier areas, tertiary recovery, stripper wells and low gravity crude oils. The ECPA specifically addressed the latter three classes by statutorily exempting stripper well oil from first sale price regulations, and by authorizing the President to provide additional price incentives for tertiary production and to adjust gravity differentials.

Four possible Stage III options were evaluated -- two alternatives designed to provide special incentives to tertiary production, one to favor low gravity California crude oils, and one to favor offshore and deep onshore low-production-rate wells. As was discussed at the beginning of this chapter, wellhead prices in frontier areas are expected to be about the same whether determined by upper tier price regulations or by competition with imported crude oil. So there is no pricing policy that could be of significant assistance to such oil.

The other "Stage III" price control options were assumed to be in effect in all cases, including the Base Case and Stage II Cases. First, in accordance with the ECPA, stripper well production was considered to be exempt from price regulation, i.e., it receives the free market price. Second, stripper, property redefinition and BPCL adjustment regulations were assumed to have the effect of reclassifying lower tier production at a rate of about 5 percent per year. Consequently, the current lower tier production class will disappear at a rate of about 10 percent per year -- 5 percent due to physical depletion,[1] and an additional 5 percent due to reclassification to stripper or upper tier. This subject is developed further in Appendix G.

There are 12 Stage III cases. Each of the four incentive options was evaluated in conjunction with each of the three Stage II pricing options, giving rise to (4 x 3 =) 12 Stage III cases.

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[1] Data Input to Project Independence Evaluation System Run OBAU 1212. November 15, 1975.

## Case IIIA -- Tertiary Production at Free Market Price

In this option all production attributable to bona fide tertiary projects could be sold at the free market price.[2] To maintain the composite price at the statutory level, the price of other classes of production must be reduced by a compensating amount. If this option is combined with Stage IIA pricing (equal price adjustments to both tiers), both upper and lower tier average prices will be lower than they would be in the absence of option IIIA. If option IIIA is combined with IIB or IIC pricing the upper tier must furnish the entire compensatory price decrease.

## Case IIIB -- Total Tertiary Project Production at Free Market Price

In this option all production at tertiary projects, including primary and secondary production as well as tertiary, could receive the free market price. A greater volume of oil could receive the free market price in this option than in option IIIA. So a commensurately greater price impact on non-advantaged classes would have to take place. Moreover, the "bonus" primary and secondary production is essentially all lower tier oil. So the effect of upgrading it to free market price is two-edged, i.e., high-priced barrels are added to the composite calculation while low-priced barrels are taken away.

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[2] As shown below in Figures III-2 and III-3, the response of tertiary production to price is relatively less elastic at high prices than at lower prices. Because of this, the increase in tertiary production between free market prices and upper tier prices is substantially less than it is between lower tier prices and upper tier prices. In view of this, and because it is not presently possible to quantify precisely the production response difference between upper tier and market prices, the quantitative environmental effects of permitting upper tier prices may appropriately be considered to be within the same range as for free market prices. In any event, quantification of environmental effects at free market prices states the upper limits for effects at the (lower) upper tier prices.

### Case IIIC -- Redefine Strippers

In this option the definition of stripper wells is broadened from the current requirement of maximum 10 barrels per day average annual production to include (1) offshore production from wells in more than 20 feet of water with annual average production less than 40 barrels per day and (2) production from onshore wells deeper than 6,000 feet with annual average production less than 20 barrels per day.

Production in these classes is almost all lower tier. Here, again, the option would remove low-priced production from the composite calculation and add high-priced. The average prices of non-advantaged classes would have to be reduced to compensate.

### Case IIID -- Reduced California Gravity Differential

The current lower tier pricing schedule in California contains a price/gravity relationship of 6 cents per degree API. Except for California and Alaska, the relationship throughout the United States is almost universally 2 or 2.5 cents per degree API. The effect of the 6 cent scale is to create much lower prices for low gravity California crude oils than for other low gravity crude oils. In this option, the price/gravity relationship would be changed to 3 cents per degree API, thus raising controlled prices for low gravity California crude oils.

This option has only a slight effect on the composite because the prices of the affected oils will be raised by only a relatively small amount. Even after adjustment, the average price of this class will be below the average lower tier price.

As has been discussed, the statutory composite price must remain at $10.44 per barrel even when an incentive price is granted to a special class. Because of this fact, most of the extra revenue given to a special class, when it is permitted to receive free market or upper tier price instead of lower tier price, must be taken away from classes not receiving an incentive. (Since some of the special classes are calculated in the composite at upper tier price rather than actual price, only about three-fourths[3] of the increased revenues received by these special classes is "taken"[4] from other classes -- the balance will be furnished by consumers of oil products.) Because price reductions may lead to production reduction, in some cases the special class incentives may be counterproductive, that is, more production is lost in non-incentive classes than is gained in the special incentive classes. In such cases imports will rise.

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[3] $\frac{\text{Upper tier price - lower tier price}}{\text{Free market price - lower market price}} = 0.6 \text{ to } 0.79,$ depending on the case.

When the gravity differential in California is decreased (Case IIID), the additional revenue received by California producers is all furnished by countries that export crude oil to the United States. This is a result of the arithmetic of the composite. When the gravity differential is reduced, the price of then-current California low gravity production increases, which increases the U.S. lower tier average price. But, also, additional production is brought forth at prices below the lower tier average, which reduces the average. The net effect on the composite price of these opposing trends is nil. So the effect on other U.S. production is also nil. Thus, the overall result of reducing the California gravity price differential is a substitution of lower tier U.S. oil for imports. (It must be noted that this discussion assumes that California heavy crude oil will be purchased by refiners at the new higher prices. Due to the entitlements system, this assumption may not be warranted for all heavy crude oils.)

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[4] This does not necessarily imply actual price reductions, either nominal or real, for any non-advantaged class. However, at a minimum it means that these classes cannot receive the same positive incentives through scheduled price increases that they might otherwise receive under existing authority. Of course, actual price reductions are a possible consequence.

# CHAPTER III

## METHODOLOGY

### A. Introduction

Two parameters determine the response of oil production to Stages II and III pricing policies -- future price expectations, and cost/volume relationships reflecting underlying geological and engineering factors. (Future income tax rates and expenditure writeoff regulations are also important, but were not considered in this analysis. That is, tax rates and regulations were implicitly assumed to continue at current levels.)

There are no historical data about the medium-term or long-term responses of production to price at price levels in the range of current and proposed upper tier prices. Such prices were never experienced before 1974.[1] Of course, this subject has received intense study since the 1973 embargo. A great deal of work has been done by, or for, the Federal Energy Administration. Recent FEA studies incorporating the PIES model were used as a basis for the price/production relationships used in this environmental impact analysis of price regulations.

Price is a difficult subject to analyze in this study. The difficulty is created because all crude oil price controls are statutorily scheduled to end on May 31, 1979. Thereafter, all domestic crude oil will likely be sold in parity with the price received by delivered imported crude oil (including any tariff), less the cost of transportation needed to move the domestic oil from the wellhead to a refinery.

The 2.5-year period from now until price controls end is not very significant to the evaluation of the economic attractiveness of a new oilfield investment. Two examples will be developed to illuminate the problem. The data used in both examples were chosen to depict typical projects.

The first example is the development of a new oil field or reservoir. (Because of lead time considerations, exploration decisions taken today cannot possibly have any measurable effect on 1979 production.) It is assumed that the field will deplete at a rate of 8 percent per year for 20 years and then be abandoned.[2] Free market price is assumed to be $12.50 per barrel ($13 delivered less $0.50 transportation cost). Upper tier price is assumed to be $7.25 per barrel, the average observed for the Base Case. A discount rate of 8 percent per year was utilized. The value is appropriate for estimating the long-run cost of equity capital in the United States.[3]

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[1] Stated in 1975 dollars, the highest annual average U.S. price experienced in 1947/1973 was $5.80 per barrel in 1957. The 1973 price was $5.10 (American Petroleum Institute, Basic Petroleum Data Book, Section IV, Table 1).

This project was evaluated for two price schedules -- $12.50 per barrel for 20 years, or $7.25 for the first 2 years plus $12.50 for the remaining 18 years. The discounted weighted average price received by the project from the first price schedule is, of course, $12.50 per barrel; for the second schedule it is $11.00 per barrel.[4] This is a small difference. Moreover, with one minor exception, the highest price on the upper tier supply curves developed later in this chapter (Figure III-2) is below $11.00 per barrel. Clearly, a 2-year period of price control regulations would have a negligible impact on investment in new field development projects.

The second example of the effect of a short period of price regulation is a short-lived tertiary project. It is assumed that this project will produce at a constant rate for 6 years and then be abandoned.[5] As before, free market price is assumed to be $12.50 per barrel, and, as above, a discount rate of 8 percent was utilized. In this example, however, the production is assumed to be lower tier with a wellhead price of $4.20 per barrel, the mid-1979 price for Stage IIC (constant lower tier nominal price).

This project was evaluated for two price schedules -- $12.50 per barrel for 6 years, or $4.20 for 2 years plus $12.50 for the remaining 4 years. The discounted weighted average price received by the project from the first price schedule is, of course, $12.50 per barrel; for the second schedule it is $9.30 per barrel.[6] Looking ahead to Figure III-3, it can be seen that the output difference in 1979 between these two prices is small -- roughly 15 percent. But the weighted average price of projects under price control increases steadily toward $12.50 per barrel as startup dates get nearer and nearer to the decontrol date. So the average effect of the second price schedule during the remaining 2.5 years of price control is less than 10 percent of lower tier tertiary production, or 0.3 percent of total domestic production. Consequently, in this example too, a 2-year period of price controls would have a negligible effect on total 1979 U.S. crude oil production.

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[2] This unrealistic assumption leads to an overstatement of the difference between the two price schedules, so does not invalidate the conclusion. In practice, secondary recovery operations would be started before abandonment.

[3] Fortune (December 1974): 100.

[4] Calculations are shown in Appendix H.

[5] A bell-shaped history of production rates is more typical of many tertiary projects. Such a history would reduce the difference between the price schedules evaluated here.

[6] Calculations are shown in Appendix H.

In this study, production forecasts are used as input to environmental impact estimates. It is important not to underestimate the environmental effects of alternative pricing policies. Consequently, a set of perceived prices was assumed that would be sure to lead to production estimates that would bracket the (unknowable) actual production rates, whatever they are. The set of bracketing prices was chosen to magnify the production differences between the Base Case and the price incentive cases, and among the several price incentive cases. The bracketing set is the May 1979 prices that would be achieved under price control regulations (including Base Case controls). That is, the 1979 production forecast in each case was derived from an assumption that the effective price used to evaluate the economics of all production projects would be the average May 1979 real price permitted by FEA regulations for that class of production. For example, in Section C of Chapter II, it is shown that the average price permitted in May 1979 for lower tier production in Case IIB (constant lower tier real price) is 4.90 real dollars per barrel. So the quantity of production in 1979 for each class of lower tier crude oil is the intercept of a $4.90 per barrel real price with the 1979 long-run supply curve for that class.

The true effects of Stage II and III pricing alternatives cannot be determined for 1979 because investors are uncertain about the level of crude oil prices after May 1979. This is for the reason that potential investors have received reports, opinions, and statements which may indicate to them that price controls may not actually expire in 1979, or because they may harbor that opinion for other reasons. Because of such information inputs, the crude oil investor is far from certain about the price which he will receive for his oil after mid-1979. He is forced to guess. In more formal terms, he will decide to invest or not on the basis of his perception of the weighted average price for his project. The proper analysis to perform for this study, therefore, would be based on the impact of Stage II and III policies on "perceived prices." But no one knows what the distribution of perceived prices is, much less how they might be quantitatively affected by pricing policies.[7]

Therefore, an approach was adopted, i.e., the bracketing approach described above, to insure that environmental effects of the alternatives would not be understated.

Although the approach just described is useful and appropriate for bracketing 1979 production effects, it is not useful for 1985. A basic assumption underlying the 1985 evaluation is that crude oil price controls will actually expire on May 31, 1979. On that day the uncertainty about future crude oil price controls will presumably end. During the ensuing 5.5 years (through 1984) investors will develop not only those projects that are economically attractive at free market (import) prices, but also projects that would have been attractive at lower prices but were not undertaken because price perceptions were pessimistic. In other words, it is expected that all of the oil producing investments that would have been undertaken before mid-1979 if prices had been correctly perceived will be undertaken before 1985, that is, there will be a catch-up of delayed projects.[8]

The foregoing discussion leads to the assumption that domestic crude oil production in 1985 will be essentially the same regardless of which pricing alternatives are implemented during the period preceding May 1979.[9] Inter-case differences in 1985 will be minor.

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[7] Clearly, perceived prices will be higher if controlled prices are allowed to increase during 1976/1979 than if they are held constant.

[8] To some extent this assumption will not be realized, as where start-up costs for abandoned wells are prohibitively high even at market prices for the crude oil to be derived from the project. However, the extent of this effect cannot be accurately quantified at this time.

[9] It should be recognized that production between 1979 and 1985 will not necessarily be the same regardless of pricing alternatives adopted prior to 1979, both because of lead-times involved in "catch-up" projects and because some previously abandoned properties may not be reworked as explained in the preceding footnote. However, the difference in annual production will decrease as the time elapsed from the cessation of control increases.

## B. Data Base

Discussions hereafter will frequently refer to Oil or Petroleum Supply Regions. The geographical bounds of the several regions are shown in Figure III-1.

Principal data sources used in this work are as follows:

1. Price/volume relationships for primary and secondary production were taken from Project Independence Evaluation System (PIES) computer run #OBAU1212 of November 15, 1975. The specific outputs utilized were entitled "Vintaged Production from Region XX." A set of these tables for Oil Supply Region 8-9-10 appears in Appendix F. The tables entitled "Type ID 1 and 2" were used to construct supply curves for production from post-1975 wells. This oil will all be upper tier. Tables ID 4 and 5 were reviewed for supply prices for pre-1976 wells. Much of this oil is lower tier, but some is upper tier.

2. Price/volume relationships for tertiary production in the three predominant states -- California, Texas and Louisiana -- were developed from "The Potential and Economics of Enhanced Oil Recovery,"[1] a study performed for the Federal Energy Administration.

3. For tertiary production in regions other than the three principal ones, PIES was utilized. Tables ID 3 and 6 of the "Vintaged Production..." series show the price/volume relationship for these other regions. In 1985, tertiary production outside the three major states is shown there to total 0.11 million barrels per day. Tertiary production in 1979 in these other regions was estimated to be nil on the basis of PIES and the Oil and Gas Journal survey.

4. Data used to evaluate the effect of redefining low-production-rate offshore wells from lower tier to stripper category were taken from a well-by-well survey by the U.S. Geological Survey of production of all wells in the Gulf of Mexico.[2] Summaries of data

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[1] Lewin and Associates, Inc. FEA Contract CO-03-50222-000, April 1976.

[2] J.B. Lowenhaupt, Approved Maximum Efficient Rates for Reservoirs and Maximum Production Rates for Well Completions, U.S. Department of Interior, Geological Survey, Conservation Division, Gulf of Mexico Area - OCS, April 1, 1976.

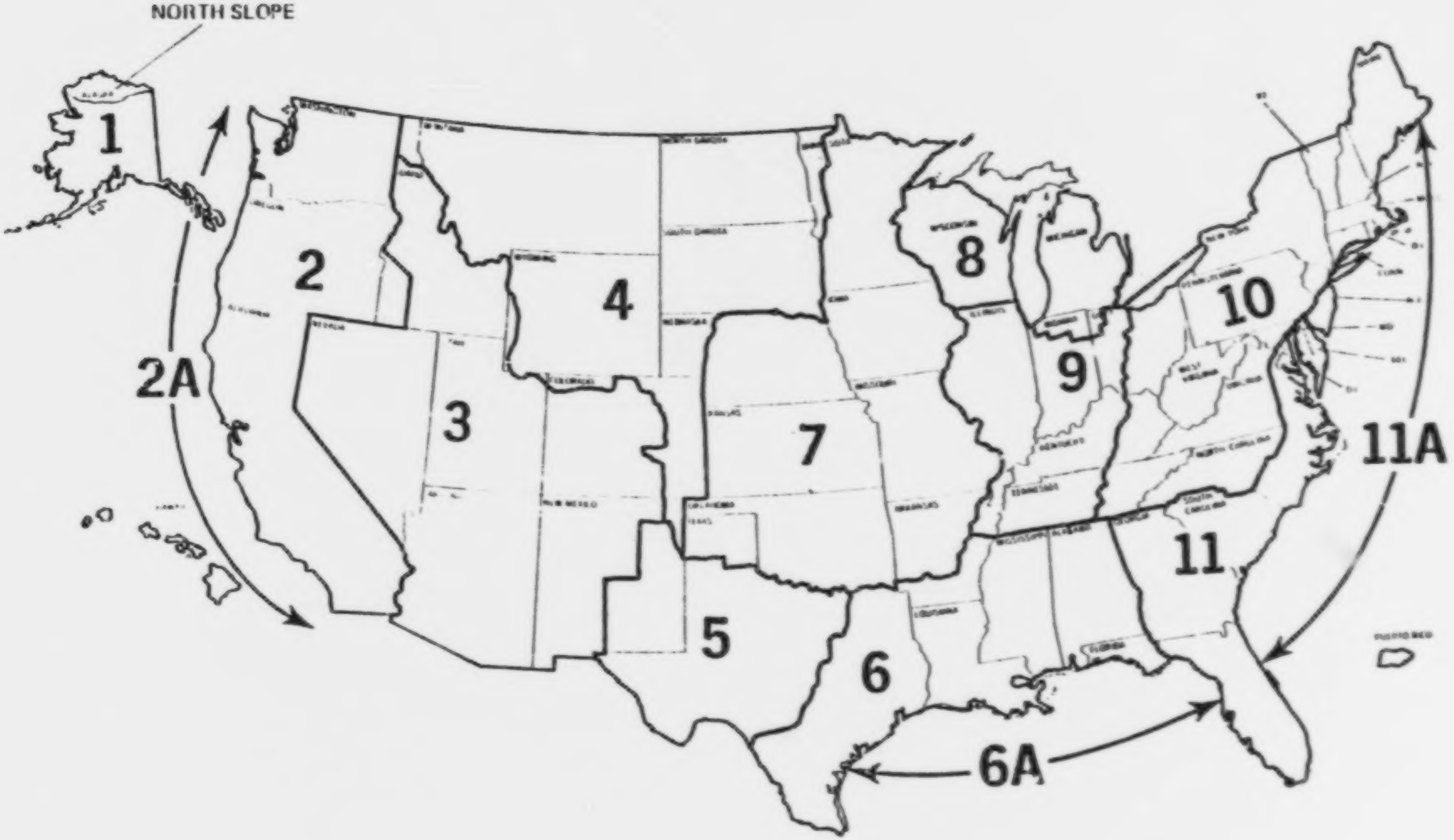
NORTH SLOPE
1
2
2A
3
4
5
6
6A
7
8
9
10
11
11A

Figure III-1. Petroleum Provinces of the United States.

from this report were utilized in this analysis. The analysis of redefining to stripper of deep onshore low-production-rate wells was based on an industry tabulation of number of wells by depth by production rate for 1971.

5. The effect of reducing the rate of change of price with gravity in California was determined to be .02 million barrels per day in 1979.

6. The relationship of production to price of wells producing less than 10 barrels per day is important because this oil would be lower tier were it not for the special treatment awarded such "stripper" wells. The stripper well analysis began with actual production by such wells in 1974.[3] The effect of price on future stripper well production was derived from a detailed study performed at the Colorado School of Mines.[4]

7. Lower tier production rates for the total United States for each of the first 6 months of 1976 were based upon production quantities contained in required monthly reports.

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[3] Oil and Gas Journal (November 3, 1975): 23.

[4] Oil and Gas Journal (January 7, 1974): 71.

## C. Production Impact Methodology

This section summarizes the methodologies used in establishing the impacts of pricing policy on crude oil production. Appendices E, F, G, and H are concerned with stripper well production, the derivation of supply curves, option-independent and lower tier production, and the impact of price controls on the average revenue of typical production projects, respectively.

### 1. 1979 Production Forecasts - Base Case and Stage II Price Policies

Five classes of production were considered:

a. Stripper production.
b. Lower tier primary and secondary production.
c. North Slope production.
d. Upper tier primary and secondary production.
e. Tertiary production.

The supply relationships for each of these classes will be discussed below.

a. Stripper oil. Stripper production, because it always is priced at the free market level, will be unaffected by Stage II and III price options. A value of 1.115 million barrels per day was utilized for stripper production in 1979. This value was derived by using the Colorado School of Mines study referenced in B.6 above. This work relates stripper production to the ratio of crude oil to stripper well operating costs. The derivation is described in Appendix E.

b. Lower tier primary and secondary production. The supply cost of all of this oil, as reported in the PIES tables referenced in B.1 above, is below $4.00 per barrel. Because the lowest price encountered in any price option is $4.20, the quantity of this production will be unaffected by the price option. Consequently, a constant quantity was used in all cases.

The quantity used was 3.07 million barrels per day. This value was derived from the mid-1976 lower tier production rate (4.46 million barrels per day average for June/July 1976).[1] The mid-1976 rate was first adjusted to exclude tertiary production (0.26 million barrels per day).[2] The resulting quantity was then declined at a rate of 10 percent per year for 3 years to get to the 1979 estimate. The 10 percent per year rate is a combination of physical depletion and of reclassification of lower tier properties to upper tier or stripper.

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[1] Data from FEA Compliance Section.

The combined depletion/reclassification rate had been estimated as 8 percent per year last spring when proposed Stage II pricing regulations were first announced.[3] Since then the opportunities to reclassify production have been further broadened.[4] Lacking data, a value of 10 percent per year was assumed.

Lower tier primary plus secondary volume in 1979 would be less than 3.07 million barrels per day if Stage IIIB were implemented. This option permits any primary and secondary crude oil that is co-produced with tertiary oil to be sold at the free market price. Consequently, lower tier volume would be reduced to the extent that the co-produced oil would otherwise be lower tier. The volume is estimated later in this chapter.

Lower tier primary plus secondary production would be greater than 3.07 million barrels per day if Stage IIID were implemented. This option permits higher prices for low gravity California crude oils. The additional production kept from abandonment by this option would be lower tier oil.

Some additional detail on lower tier primary and secondary production is given in Appendix G.

c. Alaskan North Slope Oil. The volume of this production was set at 1.42 million barrels per day in all cases. This is the "business as usual" values developed in the *1976 National Energy Outlook*.[5]

d. Upper tier primary and secondary production. Upper tier oil includes all output from leases that began production after mid-1972, plus output from older leases that were reclassified from lower to upper tier under the "released" oil incentive program or the Stage II and III property redefinitions. The older oil has a low supply price, as does lower tier oil. On the other hand, some of the oil to be produced from fields that have not yet been leased or produced will be expensive.

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[2] *Oil and Gas Journal* (April 5, 1976): 107 ff.

[3] *Federal Register* (March 4, 1976): 9389.

[4] *Federal Register* (August 26, 1976): 36172.

[5] Federal Energy Administration, *1976 National Energy Outlook* (February 1976): 97.

Consequently, the upper tier primary plus secondary cost/quantity relationship (supply curve) was developed in three steps. First, all 1979 primary plus secondary production from pre-1976 wells cost less than $4.20 per barrel (see Tables III-1 and III-2, which represent PIES vintaged production tables ID 4 and 5). So all of this production will take place in all cases. Hence, the upper tier portion of this class was derived by subtracting the lower tier portion (C.1.b above) from the PIES total.

Primary and secondary production in 1979 from post-1975 wells includes both low- and high-cost segments. The data appear in PIES vintaged production tables ID 1 and 2 which appear as Tables F-1 and F-2 in Appendix F, and are similar to Tables III-1 and III-2. The "low-cost" segment is that with a supply cost below 7.25 real (1975) dollars per barrel (the lowest upper tier price experienced - in the Base Case). A discussion of the production and cost implications of this oil is contained in Appendix G. This oil will be produced in every case, so it was explicitly identified. The high-cost segment of the 1979 upper tier production is projected for each different region as shown in Figure III-2.[6]

The supply curves shown in Figure III-2 for Regions 2 and 6 include small quantities (30 thousand barrels per day each) of production that were not included in the PIES vintaged production tables. These represent production of "heavy" crude oil from post-1975 tables. The price/supply relationships for this class of production were input to the PIES model independently from the vintaged production tables.[7] They are: for Region 2 heavy crude oil from post-1975 wells, 30 thousand barrels per day in 1979 at $7 per barrel real wellhead price; for Region 6, 10 thousand barrels per day at $7 per barrel and 30 thousand at $12.

More detail about the four production classes so far discussed is presented in Appendix G. In particular, regional information is shown.

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[6] A detailed example of the derivation of the supply curve for Regions 8, 9, and 10 is presented in Appendix F.

[7] North Slope and NPR-1 (Elk Hills) production were also input to PIES independently from the vintaged production tables.

# TABLE III-1

## VINTAGED PRODUCTION FROM REGION NO. 810L - TYPE ID: 4

(RUN: OBAU1212 - 11/15/75)

| YEAR PROVED | $ / B | YEAR PRODUCED: MB/D<br>1975 | 1976 | 1977 | 1978 | 1979 | 1980 | 1981 | 1982 | 1983 | 1984 | 1985 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1975 | 3.53 | 198 | 172 | 150 | 131 | 114 | 99 | 86 | 75 | 65 | 57 | 49 |
| 1976 | 0.0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 1977 | 0.0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 1978 | 0.0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 1979 | 0.0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 1980 | 0.0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 1981 | 0.0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 1982 | 0.0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 1983 | 0.0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 1984 | 0.0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 1985 | 0.0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

## TABLE III-2

## VINTAGED PRODUCTION FROM REGION NO. 810L - TYPE ID: 5

(RUN: OBAU1212 - 11/15/75)

| YEAR PROVED | $ / B | YEAR PRODUCED: MB/D<br>1975 | 1976 | 1977 | 1978 | 1979 | 1980 | 1981 | 1982 | 1983 | 1984 | 1985 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1975 | 0.56 | 0 | 15 | 13 | 11 | 10 | 9 | 7 | 6 | 6 | 5 | 4 |
| 1976 | 0.56 | 0 | 0 | 15 | 13 | 11 | 10 | 9 | 7 | 6 | 6 | 5 |
| 1977 | 0.56 | 0 | 0 | 0 | 15 | 13 | 11 | 10 | 9 | 7 | 6 | 6 |
| 1978 | 0.60 | 0 | 0 | 0 | 0 | 15 | 13 | 11 | 10 | 9 | 7 | 6 |
| 1979 | 0.61 | 0 | 0 | 0 | 0 | 0 | 15 | 13 | 11 | 10 | 9 | 7 |
| 1980 | 1.61 | 0 | 0 | 0 | 0 | 0 | 0 | 14 | 12 | 10 | 9 | 8 |
| 1981 | 1.62 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 14 | 12 | 10 | 9 |
| 1982 | 1.62 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 14 | 12 | 10 |
| 1983 | 1.62 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 14 | 12 |
| 1984 | 1.63 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 14 |
| 1985 | 2.65 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

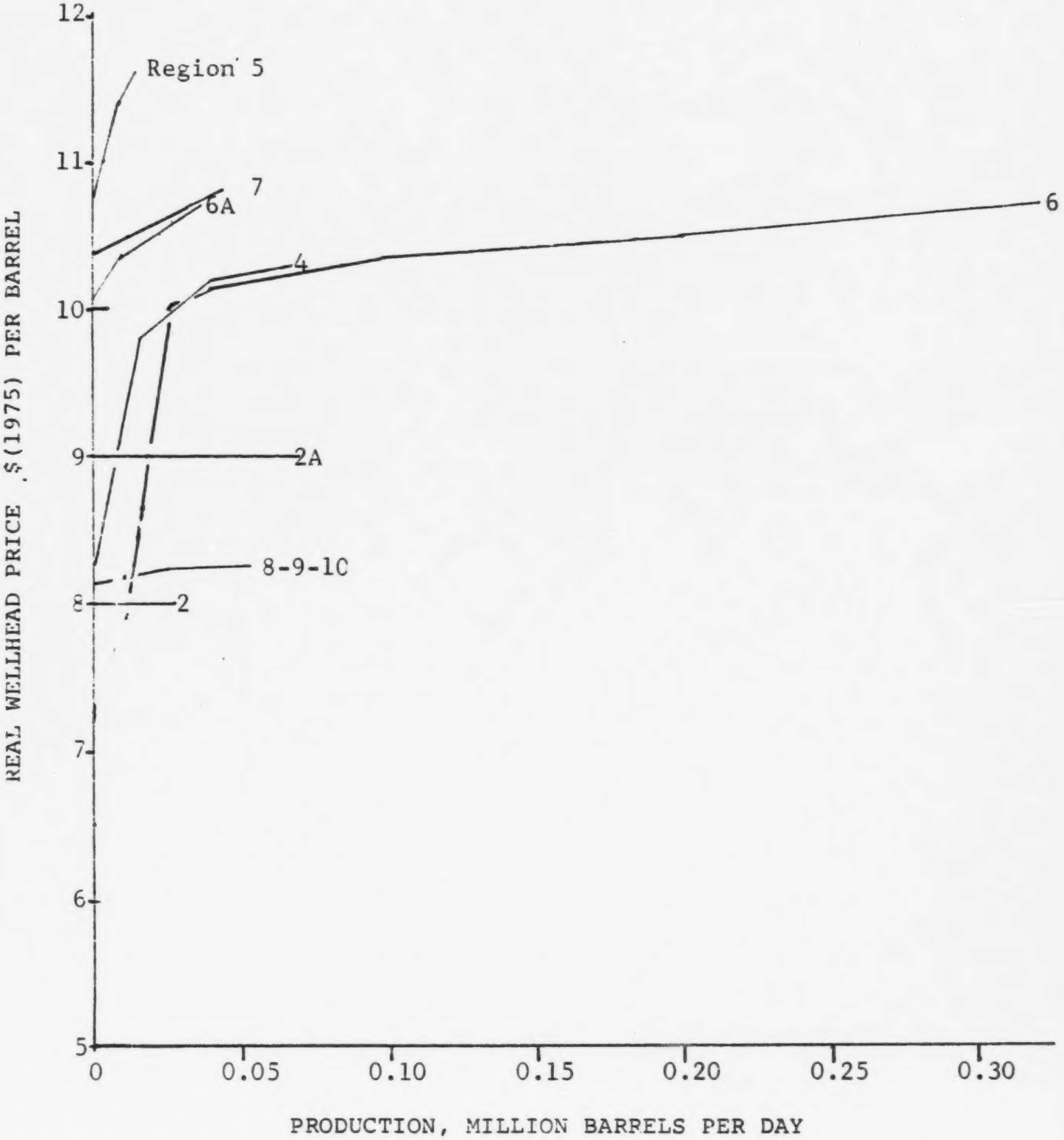

Figure III-2. Supply curves for high-cost segments of upper tier production in 1979.

e. Tertiary production. Supply curves for tertiary production in Regions 2, 5, and 6 were derived from the Lewin and Associates report referenced in 3.2 above. The derivation is described in Appendix F. The resulting supply curves are shown in Figure III-3.

No data were available about the distribution of future tertiary production between lower and upper tiers. However, for purposes of bracketing environmental effects, it was assumed that all tertiary production in 1979 would be lower tier (except, of course, in Stages IIIA and IIIB). Moreover, neither of the recent property definition adjustments[8] relieve a property of its current "cumulative deficiency" (of production below BPCL).[9] Most candidates for tertiary exploitation are older properties nearing the end of their primary and secondary useful lives. It is just such properties that usually fail to meet their BPCL and, consequently, are faced with ever-growing cumulative deficiencies to be overcome before any production can be classified as upper tier.

Production in 1979 for the Base Case and Stage II cases was computed from the supply curve data shown in Figures III-2 and III-3. For each case, an iterative algorithm was needed, because both lower tier tertiary oil quantity (Figure III-3) and upper tier high cost quantity (Figure III-2) are price-dependent. For example, in the Base, IIB and IIC Cases, lower tier price is defined. (In IIA, both lower and upper tier prices are variable.) So it was necessary to assume an upper tier price, from this determine upper tier volume, and then compute the composite price for all production. If the composite price so computed was other than nominal $10.44 per barrel (nominal $7.66 in the Base Case), a different upper tier price was assumed and a new composite determined. This process continued until a $10.44 composite price was achieved.

## 2. 1979 Production Forecasts - Stage III Price Policies

Stage III price incentives are additive to the Stage II policies, so the same supply curves and iterative computational algorithm were utilized as in the Stage II cases. Four Stage III incentive price options were studied:

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[8] Chapter I, Sections 2.2 and 2.3.1.

[9] Chapter I, Section 2.2.

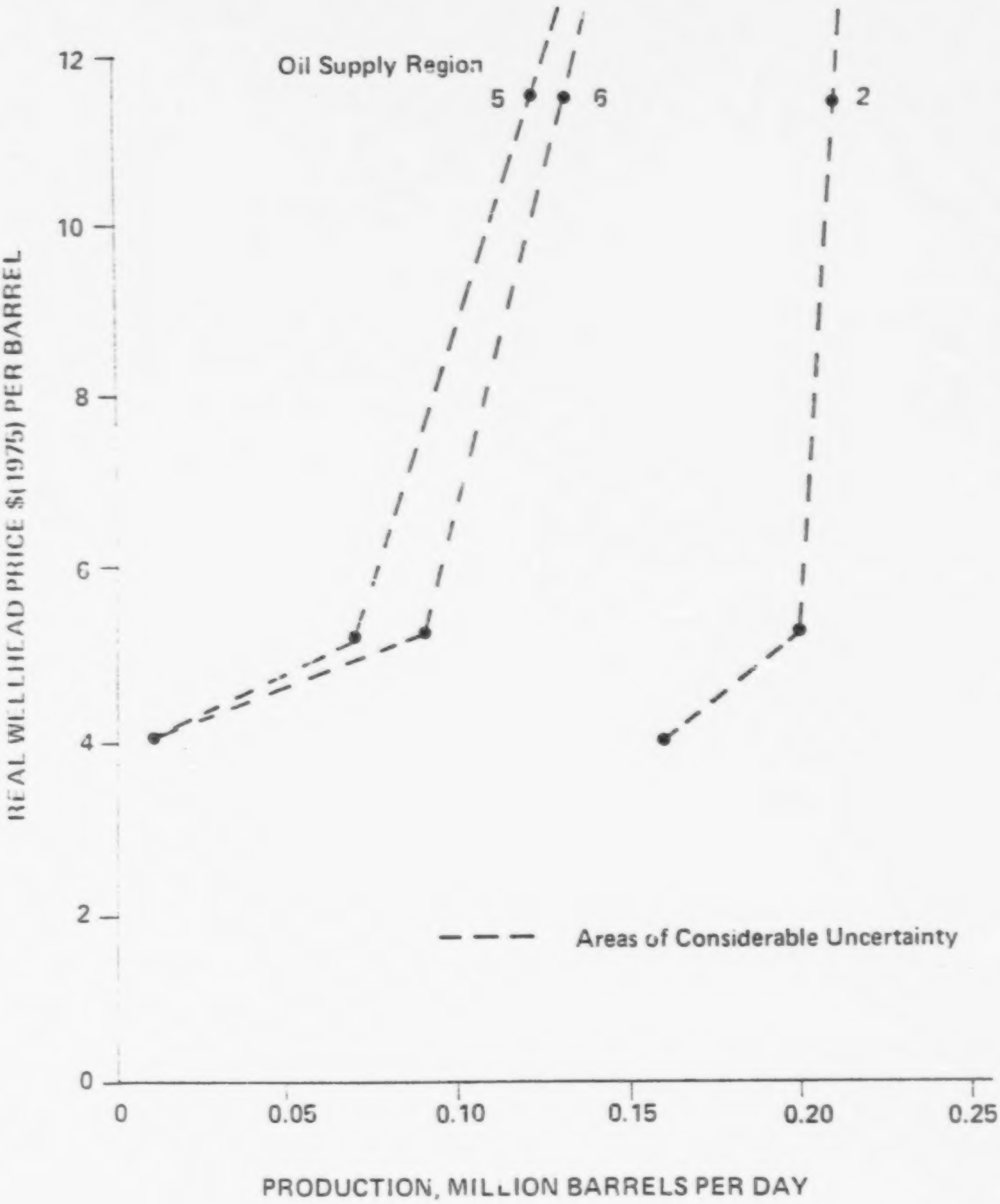

Figure III-3. Supply curves for tertiary production in 1979.

a. The first option (Stage IIIA) evaluated for Stage III was to allow all bona fide tertiary production to be sold at free market price (12.50 real dollars per barrel). Figure III-3 shows that tertiary production in 1979 at free market price would be 0.46 million barrels per day. Of course, upper or lower tier pricing policies would have no effect on this volume.

b. In the second option (Stage IIIB), as an extra incentive all production from tertiary projects would realize the free market price. That is, primary and secondary output co-produced with tertiary material would also be priced at world market level. Whether or not this is an additional incentive depends solely on the ratio of non-tertiary to tertiary production in each given project. That is, if there is no non-tertiary co-production, this option is the same as Stage IIIA. There are wide differences in the ratio of non-tertiary to tertiary production between tertiary techniques. Very little primary production is co-produced with tertiary material in steam-enhanced projects, so a value of 0.1 was assumed for the ratio. Combustion enhancement is also normally undertaken in fields where conventional production has either become uneconomical or never was economical in the first place; consequently, a ratio of 0.1 was assumed for this technique, too. Conversely, miscible floods are frequently undertaken while substantial conventional production is still underway. For this technique, a ratio of 1.0 was assumed.

Because only miscible projects are significantly advantaged by the proposed pricing option, only miscible tertiary output was increased over the previous pricing option. Based on the Lewin tertiary production study, miscible production in 1979 was increased from 0.17 to 0.23 million barrels per day, the maximum miscible quantity Lewin felt could possibly be achieved by then. Additionally, in accordance with the pricing option, 0.25 million barrels per day of lower tier oil were upgraded to free market price (0.23 million on account of miscible projects and .02 million on account of steam and combustion projects).

c. The third option (Stage IIIC) is stripper redefinition. Analysis of available data about onshore wells deeper than 6,000 feet indicated that negligible additional production would be forthcoming if deep wells producing 20 barrels per day or less were permitted free market price (instead of the current 10 barrels per day per well limit for free market pricing).[10] This conclusion was based on

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[10] See Appendix E.

1971 data which showed that at then-current prices, the minimum economic production rate for deep wells was well below 20 barrels per day per well. After adjustment for inflation, today's lower tier prices are about the same as 1971 prices. So it can be concluded that such wells still can be expected to continue production at rates below 20 barrels per day at lower tier prices. That is, onshore stripper redefinition would have nil effect on 1979 production.

The other stripper redefinition option was to redefine wells in more than 20 feet of water producing 40 barrels per day or less. The effect of this redefinition was evaluated[11] by combining the U.S. Geological Survey data discussed in B.4 above, with an estimate of offshore well economic production limits prepared by Lewin and Associates, Inc.[12] This work has been criticized as being overly simplistic. However, its overall conclusions appear reasonable, and no other immediately available estimates were known.

The results of the analysis indicate that OCS stripper redefinition would increase 1979 production by about .025 million barrels per day compared to indefinite continuation of lower tier price controls on these wells.

d. The final Stage III pricing option (IIID) to be evaluated was changing the California price/gravity relationship. It was estimated that California heavy gravity crude oil production might be increased by .02 million barrels per day by this pricing option.

### 3. 1985 Production Forecast

Forecast 1985 production by primary and secondary methods was taken from the PIES vintaged production tables described in B.1 above. Tertiary production rates in Regions 4, 7, and 8-9-10 were also taken from the PIES tables. These were disaggregated by technique (steam, miscible, etc.) in proportion to the number of projects listed in the Oil and Gas Journal survey of April 5, 1976.

Tertiary production rates for Regions 2, 5 and 6 were derived from the Lewin study referenced in B.2 above. The Lewin study reported production by tertiary technique in 1985, but not by region. Disaggregation of each technique to region was done in the same way as was done for 1979 (see Appendix F).

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[11] See Appendix E.

[12] Lewin and Associates, Inc., "Economic Limits of OCS Production Wells," FEA Contract No. CO-03-50222-000, April 1976.

## D. Environmental Impact Assessment Methodology

The environmental impacts of the alternative pricing policies are analyzed at three levels: national, regional and local. Evaluation at the national and regional levels focuses on quantifiable impacts relative to environmental policies (regulations, guidelines, standards and criteria) for purposes of comparing the alternatives. The Environmental Residual Allocation Model[1] developed for Project Independence was used for support. The regions are Demand Regions (Figure III-4) defined by FEA for Project Independence. The local analysis (see Chapter IV) is concerned with pointing out what impacts may occur.

Analysis at the local level (Chapter IV) centers around the impacts of operations of average and worst case facilities. These facilities include operations in each phase of the petroleum fuel cycle from exploration to refined product. They include exploration and drilling, production, transportation, storage and refining. Because analysis at the regional level masks impacts that may be severe at a local level, the purpose of this local assessment is to identify the impacts that will occur in the vicinity of sites where the amount or type of oil activity will change and, therefore, where the environmental impacts will actually be felt. Since it is impossible to predict the quantity or exact location of particular development activities, this local analysis does not identify specific site locations. Rather it identifies typical operation techniques, sizes and corresponding impacts.

Production is the phase of the petroleum fuel cycle most sensitive to pricing policies. Since different production technologies have significantly different impacts, the production technologies are discussed in terms of their general processes and the environmental impacts associated with those processes. Then, within any one technology, if different well characteristics such as depth, oil-to-water ratio, number of wells per unit area, gravity or age of well, imply significantly different environmental impacts, those specific parameters and impacts are addressed. Finally, as different environmental settings for the production phase, such as proximity to shores or aquifers, reflect different impacts, further analysis is given to them. Where sources of impact, such as emissions from compressors or effects of fluid injection, are common to several technologies, separate sections are devoted to their effect.

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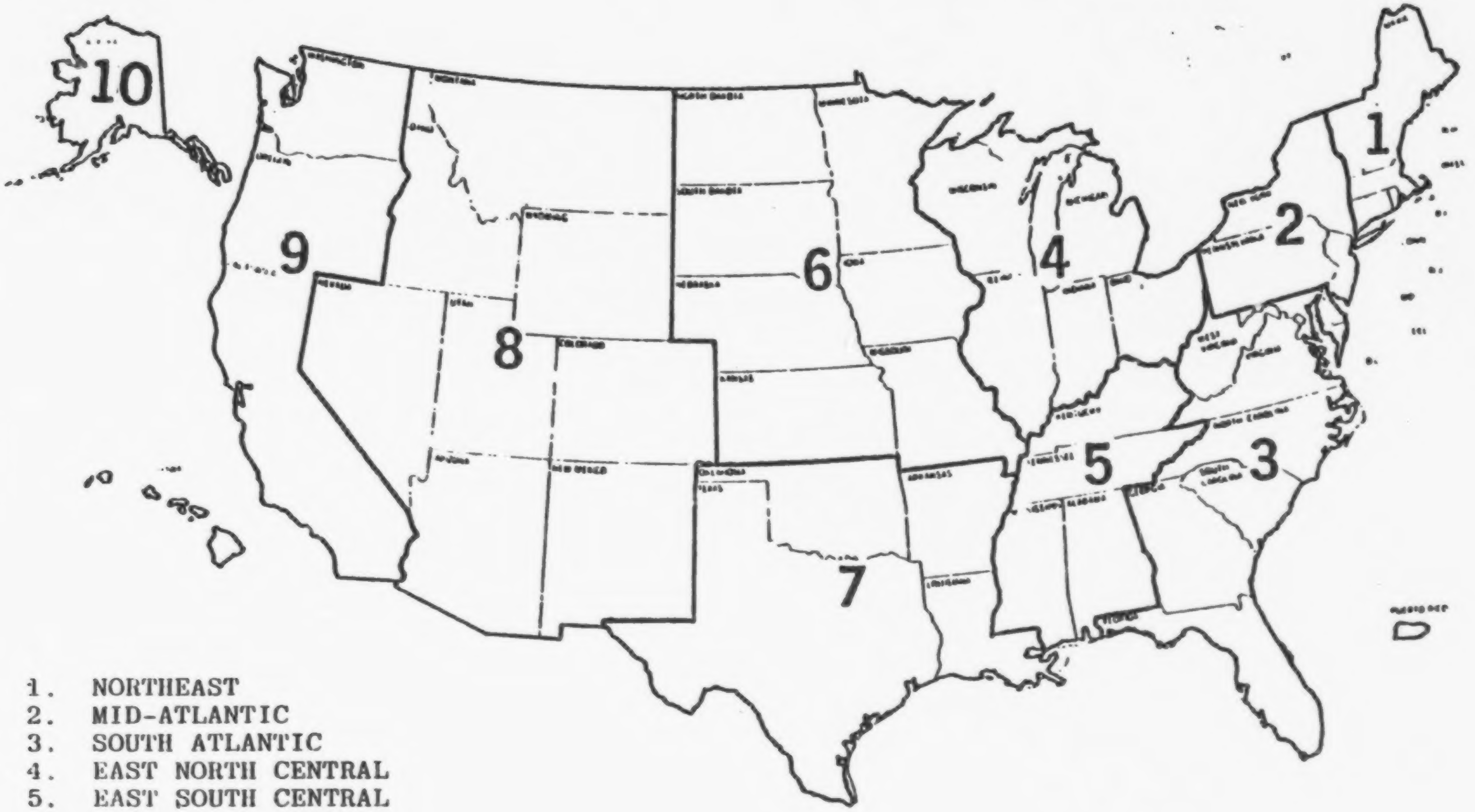
[1] Energy Resources Co. Inc., Assessment of Environmental Implications of Project Independence, for the U.S. Environmental Protection Agency, 1975.



1. NORTHEAST
2. MID-ATLANTIC
3. SOUTH ATLANTIC
4. EAST NORTH CENTRAL
5. EAST SOUTH CENTRAL
6. WEST NORTH CENTRAL
7. WEST SOUTH CENTRAL
8. MOUNTAIN
9. PACIFIC
10. ALASKA

Figure III-4. Demand Regions

The regional and national analyses (Chapter VII) deal with objective and quantitative residuals that can be related to environmental policies to compare the alternative pricing policies. The residuals are determined using the Environmental Residual Allocation Model. The format of the comparison in Chapter VII is first to relate 1975 activity to the existing environment, second to compare the Base Case to 1975 and finally to compare the alternatives to the Base Case. Where feasible, subregions such as coastal areas and specific states are also analyzed. The residuals are (1) organics in water, and (2) particulates (PM), oxides of nitrogen ($NO_x$), oxides of sulfur ($SO_x$), hydrocarbons (HC) and carbon monoxide (CO) in air. The water and air residuals and solids are given in tons per day. The residual loadings associated with an activity are computed by multiplying coefficients of residual generated per barrel of oil processed[2] times the quantity of oil predicted to be involved (see above). The coefficients are developed from the assumptions that existing laws are enforced. The assumptions include:

1. State Implementation Plans and New Source Performance Standards promulgated under the Clean Air Act will be achieved.

2. Effluent Guidelines, New Source Performance Standards and other regulations promulgated under the Federal Water Pollution Control Act will be achieved.

3. Vehicle emission control measures will be implemented.

Region and sectoral forecasts of energy consumption in 1979 were prepared for use as inputs to the Environmental Residual Allocation Model used in the regional and national analyses. Only one consumption scenario was developed for use with the production scenarios because the differences among the alternatives in amounts and patterns of consumption are relatively small, and, although consumption is the dominant contributor to environmental pollution, here the comparative effects would be almost unmeasurable within the sensitivity of the Residual Allocation Model. Our estimates, as seen below in Chapter VI, indicate a range in demand for all petroleum products from 18.62 million barrels per day for the highest priced alternative to only 18.97 million barrels per day for the Base Case.

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[2] Hittman Associates, Inc., *Environmental Residuals Coefficients for the Project Independence Evaluation System*, for the U.S. Environmental Protection Agency, Contract No. 68-01-2461, July 1976.

The consumption forecasts were prepared by interpolation and extrapolation. First, an arc elasticity was computed to represent the relationship between price and oil consumption in the United States in 1980. This was based on the $13 and $8 PIES reference cases for 1980. The elasticity so computed was -0.30. Secondly, the average price of domestic oil delivered to refineries in 1980 under Stage II pricing options was computed by adding estimated transportation costs to the wellhead prices determined above. This delivered price is $9.62 per barrel in real terms. The import price was assumed to be $13 in real terms. An iterative computation was used to balance the quantity of imports such that domestic consumption of oil was consistent with the weighted average refinery intake price of domestic and imported material. The balance point was 34 percent imports and a composite refinery intake real price of $10.77. 1980 consumption at $10.77 real oil price was computed by (logarithmic) interpolation between $8 and $13 PIES cases. These 1980 data were then extrapolated to 1979 using growth rates presented in *1976 National Energy Outlook*. Most growths were straightforward, but the change in natural gas consumption by electric utilities between 1979 and 1980 required an indirect derivation from the data given in the *National Energy Outlook*. This work showed gas consumption to be higher in 1979 than in 1980. Tables III-3 through III-6 show these inputs.

Matrices of residuals generated by region and by phase in the fuel cycle from production to consumption are prepared for each alternative to show the major impacted regions and primary sources of impact. To compare alternatives, matrices are prepared for each alternative showing the total residuals generated in the entire petroleum fuel cycle for the nation and for each region.

## TABLE III-3

## U.S. FOSSIL FUEL PRODUCTION IN 1979 WITH SECOND STAGE OIL PRICING POLICIES

A. Natural Gas Production

| REGION | PRODUCTION (million SCF/d) |
|---|---|
| 2 | 289 |
| 2A | 92 |
| 3 | 1,450 |
| 4 | 1,508 |
| 5 | 4,153 |
| 6 | 17,279 |
| 6A | 10,093 |
| 7 | 8,755 |
| 8/9 | 160 |
| 10 | 751 |
| TOTAL | 44,530 |

B. Coal

| REGION | SURFACE (thousand | DEEP tons | TOTAL per day) |
|---|---|---|---|
| Northern Appalachia | 151 | 293 | 444 |
| Central Appalachia | 292 | 446 | 738 |
| Southern Appalachia | 21 | 45 | 66 |
| Midwest | 222 | 34 | 256 |
| Central West | 25 | - | 25 |
| Western Northern Great Plains | 498 | 5 | 503 |
| Eastern Northern Great Plains | 35 | - | 35 |
| Rockies | 12 | 33 | 45 |
| Southwest | 14 | - | 13 |
| Gulf | 46 | - | 46 |
| Northwest | 3 | - | 3 |
| TOTAL | 1,318 | 856 | 2,174 |

## TABLE III-4

## ENERGY USE IN 1979 BY ELECTRIC UTILITIES WITH SECOND STAGE OIL PRICING POLICIES

| REGION | COAL (thousand tons/day) | NATURAL GAS (million SCF/day) | FUEL OIL DIST. (thousand bbl/day) | FUEL OIL RESID. | NUCLEAR (million kilowatt-hours/day) | HYDRO | GEO-THERMAL |
|---|---|---|---|---|---|---|---|
| New England | 9 | 64 | 15 | 239 | 62 | 48 | |
| Middle Atlantic | 166 | 445 | 214 | 296 | 182 | 182 | |
| South Atlantic | 298 | 309 | 57 | 244 | 241 | 157 | |
| East North Central | 375 | 442 | 114 | 68 | 198 | 39 | |
| East South Central | 180 | 318 | 43 | 25 | 123 | 102 | |
| West North Central | 144 | 310 | 27 | 1 | 50 | 62 | |
| West South Central | 40 | 5,856 | 24 | 56 | 33 | 47 | |
| Mountain | 91 | 493 | 1 | 1 | 5 | 89 | |
| Pacific | 6 | 816 | 17 | 161 | 12 | 690 | 11 |
| TOTAL | 1,309 | 9,053 | 512 | 1,091 | 906 | 1,416 | 11 |

## TABLE III-5

## REFINERY INTAKES OF CRUDE OIL AND CONDENSATE IN 1979 WITH SECOND STAGE OIL PRICING POLICIES

| PAD DISTRICT | THOUSAND BARRELS PER CALENDAR DAY |
|---|---|
| 1A | 505 |
| 2A | 2,600 |
| 3 | 5,980 |
| 4 | 410 |
| 5 | 2,570 |
| 1B | 85 |
| 2B | 645 |
| TOTAL | 12,795 |

## TABLE III-6

## SECTORAL AND REGIONAL CONSUMPTION OF ENERGY IN 1979 WITH SECOND STAGE OIL PRICING POLICIES

| SECTOR | NEW ENGLAND | MID-ATLANTIC | SOUTH ATLANTIC | EAST NORTH CENTRAL | EAST SOUTH CENTRAL | WEST NORTH CENTRAL | WEST SOUTH CENTRAL | MOUNTAIN | PACIFIC | TOTAL |
|---|---|---|---|---|---|---|---|---|---|---|
| ALL | | | | | | | | | | |
| Electricity | 233 | 884 | 1,073 | 1,088 | 602 | 422 | 650 | 290 | 726 | 5,968 |
| INDUSTRIAL | | | | | | | | | | |
| Coal | 1 | 45 | 58 | 123 | 50 | 21 | 1 | 9 | 2 | 310 |
| Natural Gas | 129 | 1,290 | 2,089 | 5,054 | 1,545 | 1,936 | 13,764 | 1,247 | 2,749 | 29,803 |
| Residual Fuel Oil | 81 | 134 | 152 | 103 | 14 | 33 | 35 | 18 | 76 | 646 |
| Distillate Fuel Oil | 19 | 54 | 85 | 89 | 38 | 30 | 52 | 43 | 59 | 469 |
| HOUSEHOLD/COMMERCIAL | | | | | | | | | | |
| Natural Gas | 541 | 2,319 | 1,250 | 5,202 | 827 | 1,780 | 1,289 | 889 | 1,892 | 15,989 |
| Distillate Fuel Oil | 296 | 512 | 179 | 310 | 21 | 110 | 23 | 31 | 56 | 1,538 |
| Residual Fuel Oil | 141 | 252 | 53 | 47 | 4 | 8 | 4 | 6 | 22 | 537 |
| TRANSPORTATION | | | | | | | | | | |
| Gasoline | 295 | 849 | 1,011 | 1,162 | 423 | 578 | 690 | 328 | 1,334 | 6,670 |
| Jet Fuel | 64 | 275 | 254 | 210 | 33 | 79 | 129 | 91 | 414 | 1,549 |
| Distillate Fuel Oil | 28 | 101 | 143 | 175 | 101 | 107 | 236 | 100 | 193 | 1,184 |
| Residual Fuel Oil | 36 | 143 | 27 | -- | 3 | -- | 27 | -- | 31 | 267 |

UNITS

| | |
|---|---|
| Coal - | Thousand "equivalent tons" (22.5 million Btu) per day. |
| Natural gas - | Million standard cubic feet per day. |
| Fuel oil, gasoline, jet fuel - | Thousand barrels per day. |
| Electricity - | Million kilowatt hours per day. |

# CHAPTER IV

## DESCRIPTION OF PETROLEUM TECHNOLOGIES AND POTENTIAL LOCAL ENVIRONMENTAL IMPACTS

The analysis in this chapter centers around the localized impacts of normal operations involved in the processing of petroleum. These include operations in each phase of the petroleum fuel cycle from exploration to refined product: exploration and drilling, production, transportation, storage and refining. Because analysis at the regional levels masks impacts that may be severe at a local level, the purpose of this local assessment is to identify the impacts that might occur in the vicinity of normal operating sites, where the major environmental impacts will actually be felt. Since it is impossible to predict the quantity or exact location of particular development activities, this local analysis does not identify the specific site locations where levels of activity will change, nor are the amounts of the changes identified. Rather, typical operation techniques, sizes and corresponding impacts are presented. The sites discussed in this chapter serve only as examples of the technology they represent. Only to the extent that activities presented here are stimulated by the pricing incentives in these or other locations will the corresponding local impacts occur. An estimate of regional production levels in 1979 under the several pricing alternatives is presented below in Chapter VI (Tables VI-3 through VI-18). The breakdown presented there, according to NPC Production Regions, is, however, too coarse to serve as a basis for pinpointing the specific sites at which production would be affected.

For certain local factors such as air emissions, which can be aggregated on a regional and national basis, estimates of overall impact are made in Chapter VII, below. These estimates indicate, in general, only small differences among all of the pricing alternatives. Localized impacts would be expected to show similar differences, considered in the aggregate, in proportion to the production level differences associated with the several alternatives. Larger differences in the nature of impact would be expected between pricing alternatives promoting different production technologies. For example, alternatives including Case IIIA or Case IIIB promote all forms of tertiary production, but particularly $CO_2$ flooding. Reference to production levels by technology in Tables VI-3 through VI-18, as noted above, will indicate the specific relationships between production and pricing alternatives.

Because production represents the phase of the petroleum fuel cycle most sensitive to the pricing policies, and since the different production technologies have significantly different impacts, the production technologies are first divided and discussed with their associated environmental impacts. Where sources of impacts, such as emissions from compressors or effects of fluid injection, are common to several technologies, separate sections are devoted to their effect.

Oil and gas are found where irregularities exist in the subsurface strata. These irregularities include faults, folds, and domes which have formed over geologic time. The fluids that may be trapped in these irregularities (reservoirs) include oil, natural gas and an aqueous, generally saline solution known as oilfield brine. Oil wells are used to tap these reservoirs and form a path for the movement of the fluids to the surface. Once the produced fluids have been extracted from the formation, they can be subjected to various processes which separate natural gas, crude oil, and produced water.

The fluids in some reservoirs are under sufficient natural pressure so that produced fluids are pushed to the surface essentially spontaneously once a well is drilled. As oil production proceeds and pressure drops, however, this is no longer the case. In order for wells to continue producing oil, pressure must be provided by pumps. Eventually, however, the production from pumped wells will drop off. This often occurs with as much as 80 or 90 percent of the original oil remaining in the reservoir. A number of strategies can be employed to produce the remaining oil.

One common strategy is the injection of fluids into the reservoir to create pressure which can drive produced fluids towards producing wells. A second technique involves modifying the properties of the oil in order to make it easier to produce; for example, heating the formation in order to decrease the viscosity of the oil. A third technique occasionally used in conjunction with fluid injection is the injection of chemicals which improve the efficiency of the operation. An example is the injection of surfactants -- chemicals which stabilize oil-water emulsions and substantially increase the amount of oil entrained by an injected stream of water. Collectively, these techniques are known as enhanced recovery methods.

Oil production techniques are commonly divided into three general categories which are referred to frequently throughout this report: these are primary, secondary, and tertiary recovery. Primary recovery refers to the production of oil when oil is allowed to flow under its own pressure or when pumps alone are used to lift it to the surface. In secondary recovery, fluids (either gas or water) are injected into the reservoir to push oil through the reservoir and towards the well. (The well through which fluids are injected into the reservoir is known as the injection well, and the well through which the produced fluids move to the surface is known as the production well. They normally are distinct.) Tertiary recovery consists of a variety of more sophisticated techniques used to increase the amounts of oil produced by fluid injection. This includes use of surfactants or other chemicals which make the oil miscible with injected water and thereby improve displacement efficiency, in addition to the use of thermal techniques which attempt to decrease the viscosity of oil in the reservoir by heating the formation (e.g., by the injection of steam).

The following oil production technologies and the environmental impacts associated with them are discussed in detail in the remainder of this chapter of the report:

## PRIMARY RECOVERY TECHNIQUES

- Onshore Primary: Oil is removed without the injection of other fluids into the reservoir; some reservoirs have sufficient natural pressure to boost oil to the surface once wells are drilled; elsewhere, pumps are used.
- Offshore Production: Oil is produced, generally by conventional primary recovery techniques, from reservoirs located under coastal waters.

## SECONDARY RECOVERY TECHNIQUES

- Waterflooding: Water is pumped into the oil reservoir through injection wells in order to drive oil over to production wells.
- Gas Injection: Natural gas is pumped under pressure into the gas reservoir to drive oil over to production wells.

## TERTIARY RECOVERY TECHNIQUES

- Steam Injection: Steam is injected into the reservoir in order to heat the formation, decrease oil viscosity, and drive oil over to the production well. This technique can be divided into steam soak, in which steam is injected into the reservoir for only a brief period of time, and steam drive, in which the steam is injected continuously. Steam injection, together with the next technique, in-situ combustion, are together referred to as thermal recovery methods.

- In-situ Combustion: Heat is generated within an oil-bearing formation through the combustion of part of the oil present in the formation. Typically, the combustion is sustained through the injection of air.

- Micellar/Polymer: A surfactant is injected into a reservoir to increase the amount of oil entrained by the water drive ("micellar" refers to the fact that surfactant molecules in the slug tend to aggregate into groups of molecules known as "micelles"). A polymeric mobility control buffer is generally also injected to push the surfactant through the formation in a piston-like motion in order to minimize diffusion and loss of the surfactant.

- Miscible/$CO_2$: $CO_2$ is injected into the reservoir at high pressures. In one approach, the $CO_2$, at supercritical pressures, acts as a mutual solvent for both the hydrocarbon and aqueous phases, forming a single phase which can be driven through the formation to the producing well. At lower pressures, the $CO_2$ acts to improve the mobility ratio, assisting in the process of moving oil toward the production well.

In addition, the following sources of environmental impact are discussed separately, since they are common to two or more of the technologies listed above:

- Impacts Due to Water Injection: Water injected into oil reservoirs for the purpose of waterflooding is generally treated with a variety of bactericides, corrosion inhibitors, and sequestering agents (scaling inhibitors). Many of these chemicals are toxic, so that the leakage of injected water from the injection well (which may occur in the case of well failure; e.g., through cracks in the well casing) may result in the contamination of groundwater supplies.

- Impacts Due to Produced Water Disposal: Produced waters contain high levels of trace heavy metals in addition to significant concentrations (20 to several hundred parts per million) of residual oil hydrocarbons. Brines from offshore production platforms are generally disposed of by being simply treated and discharged into the coastal waterbodies in which the platforms are located, while brines from terrestrial platforms are generally disposed of by being njected into underground porous formations. In the former case, brines may create levels which exceed water quality criteria. In the latter case, failure of injection wells may result in severe groundwater impact.

- Impacts Related to Use of Compression and Pumping Engines: Compression and pumping engines used in oil production operations produce emissions containing hydrocarbons, particulate matter, carbon monoxide, and oxides of nitrogen and sulfur. If the use of compressors, boilers, and the like is particularly heavy, emissions of these pollutants may cause Federal air quality standards to be violated at sites near the oil field.

- Impacts Due to Oil Spills: The storage and shipment of oil after production entail the risk of oil spills, both on land and near offshore platforms.

The processes and technologies described above create the following categories of environmental impact:

- Potential impacts on groundwater quality due to leakage of produced or injected fluids through breaks in well casings or the oil formation.

- Air quality impacts due to emissions from boilers, pumps, and compressors, and due to the release of process gases from in-situ combustion operations.

- Land use impacts; i.e., impacts on land availability related to siting and land use requirements of oil production operations.

- Impacts due to the offshore disposal of brines. Two categories of impacts are important here: ecological impacts on biological communities surrounding the production platform, and potential human health impacts as a result of the bioaccumulation of toxic brine constituents by organisms such as shellfish destined for human consumption.
- Impacts on marine biota due to offshore oil spills.
- Impacts on terrestrial vegetation, etc. due to terrestrial oil spills.
- Potential impacts created by risk of leakage of toxic chemicals used for waterflood treatment or for tertiary recovery methods from on site storage areas.

Figure IV-1 summarizes the discussions of environmental impact found in this section of the report. It shows the types of impacts which are associated with each production technology, together with parameters which can be used to express the degree of impact created by each particular technology.

|  | TECHNOLOGY |  |  |  |  |  |  |  |  |
|---|---|---|---|---|---|---|---|---|---|
| TYPE OF IMPACT | Conventional primary | Offshore production | Waterflooding | Gas Injection | Micellar/polymer | $CO_2$/miscible | Caustic flooding | Steam injection | *In-situ* combustion |
| Deterioration of groundwater quality through leakage of injected treated water in case of well failure |  |  | x |  | x | x | x |  | x |
| Groundwater quality impacts due to injection of special chemicals along with water and in addition to those commonly used for treatment of injected water |  |  |  |  | x | x | x |  |  |
| Groundwater quality impacts due to possible leakage of produced fluids | x |  | x | x | x | x | x | x | x |
| Impacts due to terrestrial oil spills | x |  | x | x | x | x | x | x | x |
| Impacts due to offshore oil spills |  | x |  |  |  |  |  |  |  |
| Impacts due to disposal of brine into coastal waters (ecological) |  | x |  |  |  |  |  |  |  |
| Impacts due to disposal of brine into coastal waters (contamination of human food organisms) |  | x |  |  |  |  |  |  |  |
| Air quality impacts due to release of process gases from production well |  |  |  |  |  |  |  |  | x |
| Air quality impacts due to use of compressors and pumps | x | x | x | x | x | x | x | x | x |
| Air quality impacts due to use of steam boilers |  |  |  |  |  |  |  | x |  |
| Water supply impacts (impacts created by high water requirements of technology) |  |  | x |  | x | x | x | x | x |
| Impacts due to potential leakage of toxic chemicals used in recovery process and stored at the field |  |  | x |  | x | x | x | x | x |

Figure IV-1. Summary of production impact matrix.

## A. Conventional Recovery Onshore

### 1. Introduction

In 1975, 3,050,819,750 barrels (96.6 percent) were produced by primary and secondary recovery techniques.[1] (105,991,250 barrels of oil were produced in the United States by tertiary recovery methods.)[2] Each production technology is described below and its relative importance in domestic oil production assessed. Sources of environmental contamination or stress are defined for each method, and the significance of the impacts evaluated.

In primary production, oil is produced without the injection of foreign substances into the reservoir. Previously untapped reservoirs often have sufficient natural pressure to boost oil to the surface once wells are drilled. Wells which produce without any assistance are called flowing wells. In 1974 only 36,105 out of 494,352 wells (7.3 percent) were flowing wells.[3] The great majority of primary oil is pumped from wells, either by mechanical pumps or by the gas lift method (discussed below). Of the total U.S. 1974 production of 3,156,811,000 bbl, 55.9 percent was recovered by primary techniques.[4]

As primary production proceeds, reservoir pressure decreases and pumping becomes inefficient. This often occurs with as much as 80 or 90 percent of the original oil remaining in place in the reservoir. Secondary methods, such as waterflooding and gas injection, may then be utilized to recover additional oil. In waterflooding, water is pumped down injection wells into the reservoir in a configuration designed to drive the oil toward production wells.

---

[1] "U.S. Thermal Recovery Activity Growing Steadily," Production Report, Oil and Gas Journal 74(14) (April 5, 1976): 107-127.

[2] Personal communication, Charles Bowlin, Director of Technical Services, Interstate Oil Compact Commission, Oklahoma City, Oklahoma.

[3] "U.S. Oil Wells Still Decreasing," World Oil (February 15, 1975): 106.

[4] Personal communication, Charles Bowlin.

Waterflooding has long been an accepted and widely used technique. According to the Interstate Oil Compact Commission:[5]

> At the present time, waterflooding is so well regarded as a reliable and economic oil recovery technique that virtually every field of any significance that does not have a natural water drive has been, is being, or soon will be waterflooded.

Gas injection is also used to maintain reservoir pressure at a level adequate to facilitate oil recovery, and to drive oil toward production wells. Most secondary recovery wells must be pumped by the same methods used for artificial lift primary wells. Secondary production presently accounts for about 40 percent of total U.S. crude production.

Potential environmental impacts associated with primary and secondary oil recovery techniques arise from four sources -- emissions from production-related equipment (compressors, injection pumps and production pumps), consumption of water in waterflooding, on-site oil spills, and brine disposal. Most oilfield equipment is now electric; therefore, equipment emissions are not a significant problem. Depletion of water supplies, while potentially a problem in particularly arid areas, has not posed and is not expected to pose a serious threat to environmental quality. Brine disposal is a problem associated with all methods of oil recovery. Under certain circumstances its impact can be significant (see Section IV.D).

### 2. Primary and Secondary Recovery Processes

In 1974, primary recovery -- both flowing and artificial lift wells -- accounted for 1,766,493,000 bbl (55.9 percent) of crude out of a total domestic production of 3,156,811,000 bbl.[6] Of the five major producing states, Louisiana had the highest percentage of primary production, at 85.1 percent of 736,415,000 bbl; Wyoming had the lowest, at 16.2 percent of 139,997,000 bbl (see Table IV-1).

---

[5] Interstate Oil Compact Commision, Secondary and Tertiary Oil Recovery Processes, Oklahoma City, Oklahoma, 1974, p. 2.

[6] Personal communication, Charles Bowlin.

## TABLE IV-1

## TOTAL 1974 CRUDE OIL PRODUCTION AND SECONDARY RECOVERY PRODUCTION

(thousands of barrels)

| STATE | TOTAL OIL 1974 | SECONDARY RECOVERY[1] 1974 |
|---|---|---|
| Alabama | 13,300 | 6,324 |
| Alaska | 72,279 | 69,699 |
| Arkansas | 16,555 | 5,461 |
| California | 322,519 | 153,170 |
| Colorado | 37,508 | 25,127 |
| Florida | 36,351 | 560 |
| Illinois | 27,553 | 19,424 |
| Indiana | 5,439 | 2,514 |
| Kansas | 61,691 | 21,317 |
| Kentucky | 7,837 | 6,661 |
| Louisiana | 736,415[2] | 109,836 |
| Michigan | 17,893[2] | 2,217 |
| Mississippi | 50,779 | 11,274 |
| Missouri | 56 | 21 |
| Montana | 34,554 | 28,836 |
| Nebraska | 6,611 | 3,271 |
| New Mexico | 94,083 | 32,916 |
| New York | 896 | 762 |
| North Dakota | 19,781 | 11,514 |
| Ohio | 9,088 | 87 |
| Oklahoma | 173,144 | 95,046 |
| Pennsylvania | 3,399 | 1,690 |
| Texas | 1,224,924 | 650,563 |
| Utah | 39,363 | 13,377 |
| West Virginia | 2,673 | 297 |
| Wyoming | 139,997 | 117,364 |
| Others[3] | 2,121 | --- |
| TOTALS | 3.156,811 | 1,390,313 |

---

[1] Total shown for secondary recovery volumes include all production from fields undergoing these processes, although it is realized that a portion of the production from some fields is primary.

[2] Bureau of Mines.

[3] Arizona, Nevada, South Dakota, and Tennessee.

Source: Interstate Oil Compact Commission and National Stripper Well Association, National Stripper Well Survey, January 1, 1975.

Secondary recovery methods include waterflooding and gas injection. In 1974, approximately 1,284,300,000 bbl, or 40.7 percent of total U.S. crude oil, was recovered by these methods. Alaska (96.4) and Montanta (83.8) had the largest percentage of crude oil production attributable to secondary recovery methods (see Table IV-1).[7] Of 74 secondary recovery projects in Montana, 3 were gas injection projects, 1 used both gas injection and waterflooding, and the rest were waterflood projects.[8]

### 2.1 Primary Recovery -- Flowing Wells

No mechanical assistance is required for production from flowing wells. Natural reservoir pressure forces the oil-brine mixture up the well to the surface. It is then piped directly to separation facilities where produced water is removed from the oil. Flowing well production is generally possible only in new, unexploited reservoirs. Production rates from these reservoirs tend to be high; water to oil ratios are relatively low.

Flowing wells represent only a small fraction of all U.S. producing wells. Eight producing states have no flowing wells at all. The percentages of wells that were flowing in the five major producing states in 1974 are as follows: Texas -- 12.5 percent; Louisiana -- 23.4 percent; California -- 1.1 percent; Oklahoma -- 5.4 percent; and Wyoming -- 7.1 percent. These five states accounted for 82.5 percent of total U.S. production in 1974[9] (see Table IV-2).

### 2.2 Primary Recovery -- Artificial Lift

Most primary oil is recovered by one of two kinds of pumping -- mechanical pumps or gas lift. There are four types of mechanical pumps commonly in use: walking beam, electric semisubmersible, subsurface hydraulic, and plunger lift. Walking beam pumps are the most widely used (see Figure IV-2). A bottom hole pump is connected by a string

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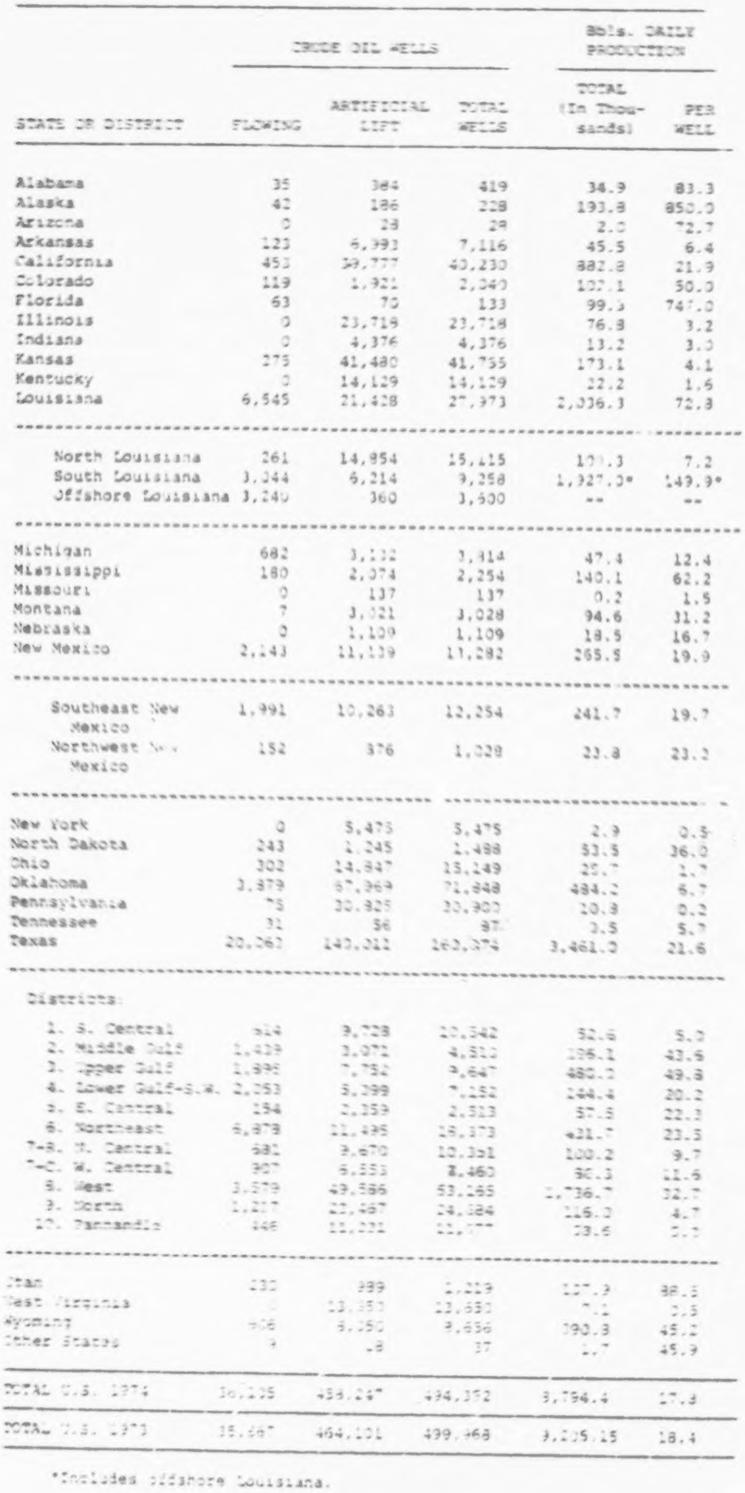
[7] Personal communication, Charles Bowlin.

[8] State of Montana, Department of Natural Resources and Conservation, Oil and Gas Division, Annual Review for the Year 1974 Relating to Oil and Gas.

[9] "U.S. Oil Wells Still Decreasing," 1975.

# TABLE IV-2

## U.S. WELLS PRODUCING CRUDE OIL AT END OF 1974, BY STATES



| STATE OR DISTRICT | CRUDE OIL WELLS |  |  | Bbls. DAILY PRODUCTION |  |
|---|---|---|---|---|---|
|  | FLOWING | ARTIFICIAL LIFT | TOTAL WELLS | TOTAL (In Thousands) | PER WELL |
| Alabama | 35 | 384 | 419 | 34.9 | 83.3 |
| Alaska | 42 | 186 | 228 | 193.8 | 850.0 |
| Arizona | 0 | 28 | 29 | 2.0 | 72.7 |
| Arkansas | 123 | 6,993 | 7,116 | 45.5 | 6.4 |
| California | 453 | 39,777 | 40,230 | 882.8 | 21.9 |
| Colorado | 119 | 1,921 | 2,040 | 102.1 | 50.0 |
| Florida | 63 | 70 | 133 | 99.3 | 747.0 |
| Illinois | 0 | 23,718 | 23,718 | 76.8 | 3.2 |
| Indiana | 0 | 4,376 | 4,376 | 13.2 | 3.0 |
| Kansas | 275 | 41,480 | 41,755 | 173.1 | 4.1 |
| Kentucky | 0 | 14,129 | 14,129 | 22.2 | 1.6 |
| Louisiana | 6,545 | 21,428 | 27,973 | 2,036.3 | 72.8 |
| North Louisiana | 261 | 14,854 | 15,115 | 109.3 | 7.2 |
| South Louisiana | 3,044 | 6,214 | 9,258 | 1,927.0* | 149.9* |
| Offshore Louisiana | 3,240 | 360 | 3,600 | -- | -- |
| Michigan | 682 | 3,132 | 3,814 | 47.4 | 12.4 |
| Mississippi | 180 | 2,074 | 2,254 | 140.1 | 62.2 |
| Missouri | 0 | 137 | 137 | 0.2 | 1.5 |
| Montana | 7 | 3,021 | 3,028 | 94.6 | 31.2 |
| Nebraska | 0 | 1,109 | 1,109 | 18.5 | 16.7 |
| New Mexico | 2,143 | 11,139 | 13,282 | 265.5 | 19.9 |
| Southeast New Mexico | 1,991 | 10,263 | 12,254 | 241.7 | 19.7 |
| Northwest New Mexico | 152 | 876 | 1,028 | 23.8 | 23.2 |
| New York | 0 | 5,475 | 5,475 | 2.9 | 0.5 |
| North Dakota | 243 | 1,245 | 1,488 | 53.5 | 36.0 |
| Ohio | 302 | 14,847 | 15,149 | 25.7 | 1.7 |
| Oklahoma | 3,879 | 67,969 | 71,848 | 484.2 | 6.7 |
| Pennsylvania | 75 | 20,825 | 20,900 | 10.8 | 0.2 |
| Tennessee | 31 | 56 | 87 | 0.5 | 5.7 |
| Texas | 20,362 | 143,012 | 163,374 | 3,461.0 | 21.6 |
| Districts: |  |  |  |  |  |
| 1. S. Central | 614 | 9,728 | 10,342 | 52.6 | 5.0 |
| 2. Middle Gulf | 1,439 | 3,071 | 4,510 | 196.1 | 43.6 |
| 3. Upper Gulf | 1,895 | 7,752 | 9,647 | 480.0 | 49.8 |
| 4. Lower Gulf-S.W. | 2,053 | 5,099 | 7,152 | 144.4 | 20.2 |
| 5. E. Central | 154 | 2,359 | 2,513 | 57.5 | 22.9 |
| 6. Northeast | 6,878 | 11,495 | 18,373 | 421.7 | 23.3 |
| 7-B. N. Central | 681 | 9,670 | 10,351 | 100.2 | 9.7 |
| 7-C. W. Central | 907 | 6,553 | 7,460 | 86.3 | 11.6 |
| 8. West | 3,579 | 49,586 | 53,165 | 1,736.7 | 32.7 |
| 9. North | 1,217 | 22,467 | 23,684 | 116.0 | 4.7 |
| 10. Panhandle | 446 | 11,331 | 11,777 | 23.6 | 2.0 |
| Utah | 130 | 889 | 1,019 | 117.9 | 88.5 |
| West Virginia | 0 | 13,850 | 13,850 | 7.1 | 0.5 |
| Wyoming | 806 | 8,050 | 8,856 | 390.8 | 45.2 |
| Other States | 9 | 28 | 37 | 1.7 | 45.9 |
| TOTAL U.S. 1974 | 36,105 | 458,247 | 494,352 | 8,794.4 | 17.8 |
| TOTAL U.S. 1973 | 35,367 | 464,101 | 499,468 | 9,205.15 | 18.4 |

*Includes offshore Louisiana.

Source: World Oil (February 15, 1975): 106.

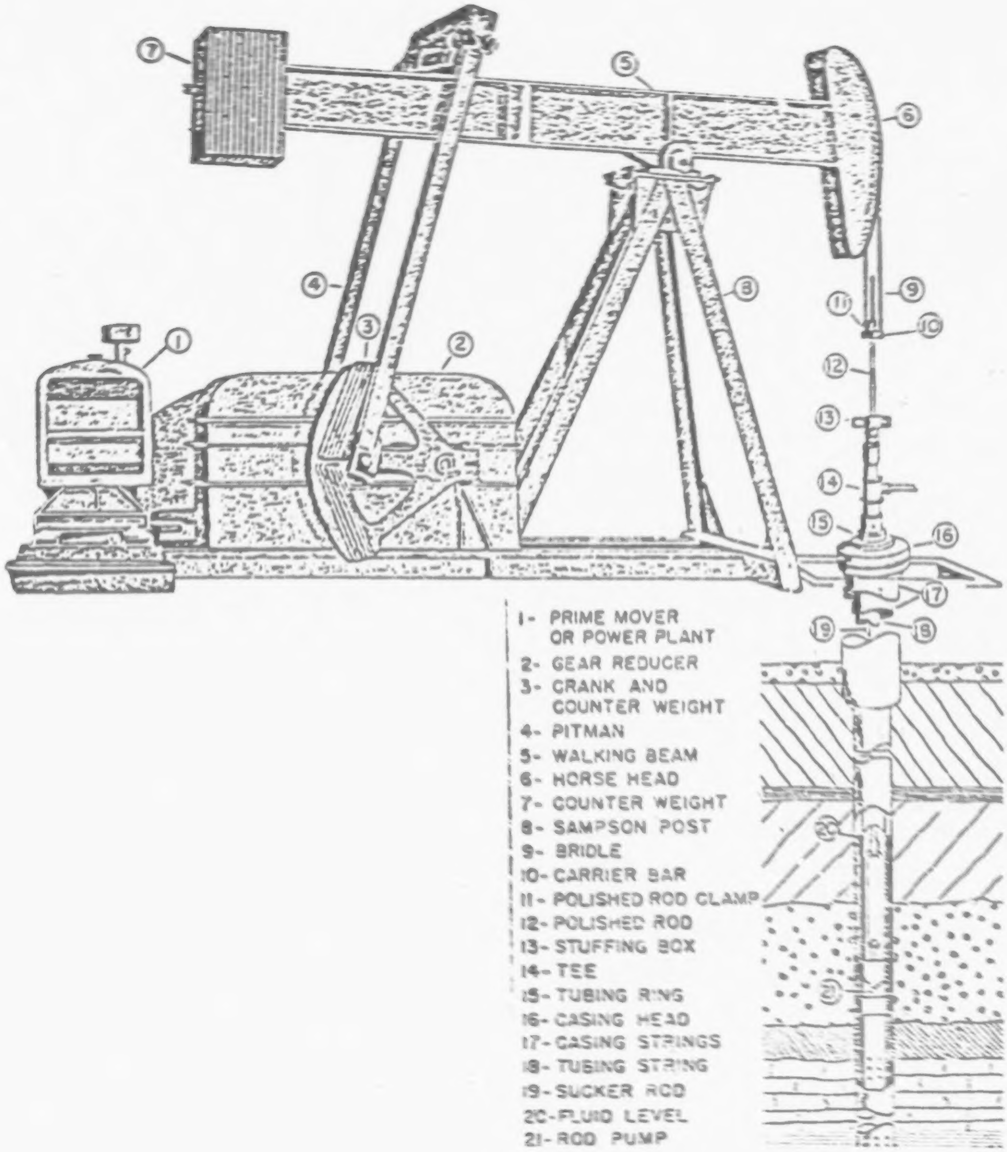

1- PRIME MOVER OR POWER PLANT
2- GEAR REDUCER
3- CRANK AND COUNTER WEIGHT
4- PITMAN
5- WALKING BEAM
6- HORSE HEAD
7- COUNTER WEIGHT
8- SAMPSON POST
9- BRIDLE
10- CARRIER BAR
11- POLISHED ROD CLAMP
12- POLISHED ROD
13- STUFFING BOX
14- TEE
15- TUBING RING
16- CASING HEAD
17- CASING STRINGS
18- TUBING STRING
19- SUCKER ROD
20- FLUID LEVEL
21- ROD PUMP

Figure IV-2. Artificial lift. (American Petroleum Institute, Primer of Oil and Gas Production, Dallas, Texas, 1973 , p. 23.)

of rods (sucker rods) to a mechanical apparatus on the surface which moves the pump up and down in the well, providing the motion necessary for pumping.

Electric submersible pumps are centrifugal pumps that are lowered to the bottom of wells, where they build up pressure sufficient to lift oil to the surface. Subsurface hydraulic pumps are also bottom hole pumps. They operate on hydraulic power supplied by an engine-driven pump on the surface.

In the plunger lift method a steel plunger is raised from the bottom of the well to the top by compressed gas injected below the plunger. As the plunger rises it pushes the column of oil above it into the flow line at the surface.

In the gas lift method, compressed gas, usually natural gas from the same well or from a nearby field, is injected into the oil column. There it mixes with the oil, expands, and displaces the oil upward in the well. Oil above the injection point is lifted, and raised to the surface by the expanding gas. In Texas in 1974, 3,739,105 thousand cubic feet (MCF) of natural gas were injected in oil recovery operations.[10]

All of the artificial lift techniques require on-site engines to supply power. The electric semisubmersible pump contains its own electric motor. The walking beam pump needs an engine to provide mechanical power; subsurface hydraulic pumping requires a source of hydraulic power; and plunger lift and gas lift methods require compressors. The engines used for these purposes are either gas or electric, depending largely on the availability of the different fuels.

### 2.3 Secondary Recovery -- Waterflooding

In waterflooding, water is pumped down injection wells in order to drive oil toward production wells. Depending on the availability of water and on the quantities required, water is obtained either from the reservoir itself, from wells drilled in nearby formations, or from surface water

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[10] Railroad Commission of Texas, Annual Report of the Oil and Gas Division, 1974.

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supplies. Water injected per barrel of oil recovered varies widely, depending on injection configuration and formation characteristics. For example, in 1974, 1.4 barrels of water were injected into the Sawtooth formation of the Bowes Field in Montana per barrel of oil produced; the Tyler formation in Big Wall Field, Montana, required 23.5 barrels of water per barrel of oil.[11] At the North Burbank field in Oklahoma in 1974, 77.2 barrels of water were injected for each barrel of oil retrieved. The field produced approximately 6,500 barrels of oil per day.[12]

Water is piped from the water supply to a water station, where it is treated, if necessary. Water quality requirements for injection water are fairly stringent. Oxygen content must be low -- under 30 ppb -- in order to avoid corrosion of tubing and equipment. Suspended solids must also be low -- less than 5 ppm -- or plugging of the injection wells may result, which necessitates the use of greater and greater injection pressures to achieve adequate production rates. Sulfate content must also be low, or reducing bacteria in the reservoir may generate dangerous amounts of $H_2S$ gas.

Following treatment, the water is pumped out under pressure from the central injection plant to a surrounding network of injection wells. Economic factors dictate the size of the area covered by a single injection plant. In general, an injection facility can provide water for injection wells within a 2-mile radius. Positive-displacement plunger pumps, centrifugal pumps, or turbines are used to supply water at pressures up to 6,000 pounds per square inch (psi). Single pumps are capable of delivering 2,844 bbl/day at 5,640 psi, or up to 26,600 bbl/day at 600 psi.[13] Several pumps are usually connected in parallel to provide necessary flow rates. Pumps are usually powered by electric motors, although multi-cylinder natural gas engines are also used.

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[11] State of Montana, Annual Review for the Year 1974.

[12] Oklahoma Corporation Commission, Oil and Gas Conservation Department, Oklahoma: Secondary Recovery and Pressure Maintenance Operations - January 1, 1975.

[13] Oil Well, Division of U.S. Steel Corporation, "Machinery and Equipment Catalog; 1976-1977," p. 4498.

Most waterflood reservoirs require artificial lift to produce oil. Pumping methods are similar to those used in primary recovery. The following two paragraphs describe two fairly typical large waterflood projects.

The facility at the large Wilmington Field in California is an example of a waterflood project. In 1974, 527,284,828 barrels of water were injected in the recovery of 65,335,801 barrels of oil.[14] Approximately 1.5 million barrels of water were injected per day from 19 injection plants.[15] Water was derived from a number of sources. Produced water was the main water source. It was treated before injection to leave only 5 ppm of oil and 5 ppm suspended solids. Freshwater was used to supplement the supply of produced water, and to reduce $H_2S$ generation. It was used with reluctance due to its high cost and limited availability. An attempt was made to inject filtered seawater. This water required treatment with corrosion inhibitors, bactericides, and oxygen scavengers. In spite of the treatment applied, many difficulties were experienced including corrosion, injection well plugging, and $H_2S$ formation. Secondary sewage effluent was also tried, but failed as a result of injection well plugging. Possibilities of using tertiary sewage effluent are now being investigated.

The North Burbank, Oklahoma, field has been waterflooded for over 25 years.[16] Initially freshwater from the Arkansas River was used for injection. Since the late 1960's, however, the produced water yield was large enough to provide sufficient water for injection purposes. The brine is not treated at all; cement and plastic well casings are used in injection wells to avoid corrosion. Eighteen water stations provide water for 480 injection wells distributed over the 22,000 acre field. Several 8,000 bbl/day pumps are used in each injection station, delivering water at a pressure slightly below 500 psi. The injected water to oil produced ratio is 77.2,[17] reflecting the age of the development.

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[14] California Division of Oil and Gas, 60th Annual Report of the State Oil and Gas Supervisor, Sacramento, Calif., 1975.

[15] "Water-Quality Control Presents Challenge in Giant Wilmington Field," Oil and Gas Journal (August 16, 1976): 115.

[16] Personal communication, Bill Dickenson, Field Supervisor, North Burbank Field, Phillips Petroleum Company, Oklahoma, September 1, 1976.

[17] Oklahoma Corporation Commission, Oklahoma Secondary Recovery and Pressure Maintenance Operations.

## 2.4 Secondary Recovery -- Gas Injection

Gas injection is similar in principle to waterflooding. Natural gas is injected into the producing reservoir under pressure. Gas injection can serve either to maintain reservoir pressure at a level adequate to sustain an economically acceptable level of production or to drive oil through the reservoir toward the producing wells. In most cases oil from these wells must be pumped. Gas injection is generally not as efficient a technique as waterflooding for improving recovery of oil and is used only where supplies of gas are readily available.

Injection gas can be casinghead gas from the producing formation, or it can be gas piped in from another formation in the vicinity of the injection project. In some instances natural gas is purchased for injection purposes when a local source is unavailable. Gas does not usually require any treatment prior to injection.

Gas injection accounts for only a small proportion of total secondary recovery. In Montana, three gas injection projects were in operation in 1974, producing a total of 1,195,303 barrels of oil.[18] During the year, 8,578,000 thousand cubic feet of gas were injected into the three fields, with injected gas to produced oil ratios of 0.162 MCF/bbl, 1.873 MCF/bbl, and 1.334 MCF/bbl Gas injection accounted for only 3.4 percent of Montana's total 1974 production. In Oklahoma in 1974, 14 gas injection projects produced a total of 2,632,187 barrels of oil (2.6 percent of the state's secondary production, or 1.5 percent of total production for the year).[19] Thirteen gas injection projects were in operation in Wyoming during 1975.[20]

In Texas, at 42 gas injection projects 62,446,189 MCF of gas were injected in 1974. Daily average injection rates ranged from 23 MCF/day to 6,034 MCF/day. At the Archer County Regular Field (injection rate = 23 MCF/day), 4.1 cubic feet were injected per barrel of oil produced; at the Harper (Devonian) Field (6,034 MCF/day) 4.059 MCF were injected per barrel of oil produced.[21] This thousand-fold difference in yield per cubic foot of gas injected illustrates the wide range of recovery efficiencies observed among gas injection projects.

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[18] State of Montana, Annual Review for the Year 1974.

[19] Oklahoma Corporation Commission, Oklahoma Secondary Recovery and Pressure Maintenance Operations.

[20] Wyoming Oil and Gas Conservation Commission, "Wyoming Oil and Gas Statistics - 1975," Casper, Wyoming.

## 2.5 Stripper Wells

Stripper wells are, by definition, wells which produce 10 barrels of oil per day or less. Stripper prices are not regulated under any of the alternatives examined, although stripper production enters into the formula for composite price.

Thus, no changes in stripper production are expected as a result of the pricing policy finally adopted.

## 2.6 Deep Horizon Wells

Deep horizon wells are defined for this analysis as wells deeper than 15,000 feet. At present, there are relatively few producing deep horizon wells in the United States. The highest concentration of these wells occurs in Southern Louisiana -- both onshore and in the near offshore. Out of the total number of producing fields in Louisiana (about 4,680), only some 150 are deep horizon.[22] Six deep horizon fields produce 35.5 percent of Alabama's total production. Florida and Mississippi also produce from deep wells.[23]

Since 1966, the number of U.S. wells drilled to 15,000 feet or deeper has hovered at around 400 wells per year. This rate reached a peak in 1972 of 486 wells and dropped to 405 wells in 1974[24] (see Table IV-3).

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[21] Railroad Commission of Texas, Annual Report of the Oil and Gas Division and Oil and Gas Annual Production by Active Fields, 1974.

[22] International Oil Scouts Association, International Oil and Gas Development, Vol. 46, Part II, 1976.

[23] International Oil Scouts Association, International Oil and Gas Development, 1976.

[24] "Deep Well Drilling Declines Again," World Oil (February 15, 1975): 91.

## TABLE IV-3

## U.S. WELLS DRILLED TO 15,000 FEET AND DEEPER

## (BY DEPTH BRACKETS) IN 1974

| Depth bracket (feet) | Alabama | Florida | Louisiana | Mississippi | New Mexico | Oklahoma | Texas | Utah | Wyoming | Other states | U.S. total 1974 | U.S. total 1973 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 15,000—15,999 | 18 | 11 | 53 | 4 | 5 | 3 | 25 | 10 | 3 | 3 | 135 | 145 |
| 16,000—16,999 | 5 | 7 | 36 | 7 | 1 | 2 | 23 | 7 | ... | 1 | 89 | 99 |
| 17,000—17,999 | 1 | . | 24 | 5 | ... | 2 | 17 | 6 | 1 | ... | 56 | 75 |
| 18,000—18,999 | 5 | | 8 | 4 | ... | 1 | 18 | 6 | 1 | ... | 43 | 32 |
| 19,000—19,999 | ... | ... | 11 | 2 | . | 1 | 5 | 1 | ... | 1 | 21 | 22 |
| 20,000—20,999 | 1 | ... | 4 | 1 | ... | 3 | 13 | ... | ... | 2 | 24 | 18 |
| 21,000—21,999 | ... | ... | 1 | ... | ... | 1 | 12 | ... | ... | 1 | 15 | 12 |
| 22,000—22,999 | ... | ... | ... | . | ... | 1 | 13 | ... | ... | ... | 14 | 18 |
| 23,000—23,999 | ... | ... | ... | . | ... | 1 | 1 | ... | ... | ... | 2 | 3 |
| 24,000—24,999 | . | ... | ... | . | ... | .. | 2 | ... | ... | ... | 2 | 2 |
| 25,000—25,999 | ... | .. | ... | . | .. | 1 | ... | ... | ... | ... | 1 | 1 |
| 26,000—26,999 | ... | . | ... | ... | ... | 1 | ... | ... | .. | . | 1 | ... |
| 27,000—27,999 | ... | . | ... | ... | ... | 1 | ... | ... | . | ... | 1 | ... |
| 28,000—28,999 | ... | . | .. | ... | ... | ... | ... | ... | ... | ... | ... | ... |
| 29,000—29,999 | ... | . | ... | ... | ... | ... | .. | ... | ... | ... | .. | ... |
| 30,000—30,999 | ... | . | ... | ... | ... | ... | ... | ... | ... | ... | ... | ... |
| 31,000—31,999 | ... | .. | ... | ... | ... | 1 | ... | ... | ... | .. | 1 | ... |
| Total | 30 | 18 | 137 | 23 | 6 | 19 | 129 | 30 | 5 | 8 | 405 | 427 |

## (BY DEPTH BRACKETS) 1966-1974

| | 1966 | 1967 | 1968 | 1969 | 1970 | 1971 | 1972 | 1973 | 1974 | Total |
|---|---|---|---|---|---|---|---|---|---|---|
| 15,000—15,999 | 145 | 132 | 147 | 132 | 130 | 120 | 187 | 145 | 135 | 1,273 |
| 16,000—16,999 | 107 | 92 | 75 | 78 | 94 | 93 | 135 | 99 | 89 | 862 |
| 17,000—17,999 | 52 | 59 | 59 | 43 | 48 | 52 | 74 | 75 | 56 | 518 |
| 18,000—18,999 | 25 | 32 | 30 | 21 | 42 | 33 | 23 | 32 | 43 | 281 |
| 19,000—19,999 | 13 | 17 | 16 | 15 | 17 | 21 | 20 | 22 | 21 | 162 |
| 20,000—20,999 | 10 | 13 | 17 | 26 | 23 | 14 | 15 | 18 | 24 | 160 |
| 21,000—21,999 | 16 | 14 | 14 | 6 | 8 | 11 | 10 | 12 | 15 | 106 |
| 22,000—22,999 | 8 | 7 | 10 | 12 | 17 | 24 | 16 | 18 | 14 | 126 |
| 23,000—23,999 | 3 | 1 | 2 | 1 | 1 | 3 | 2 | 3 | 2 | 18 |
| 24,000—24,999 | ... | ... | ... | 1 | 1 | ... | 2 | 2 | 2 | 8 |
| 25,000—25,999 | . | .. | . | ... | 1 | . | ... | 1 | 1 | 3 |
| 26,000—26,999 | ... | . | ... | ... | ... | . | .. | ... | 1 | 1 |
| 27,000—27,999 | .. | .. | ... | ... | ... | ... | ... | ... | 1 | 1 |
| 28,000—28,999 | .. | . | . | ... | ... | ... | 1 | ... | ... | 1 |
| 29,000—29,999 | .. | .. | . | ... | ... | ... | ... | ... | ... | ... |
| 30,000—30,999 | ... | .. | . | .. | ... | ... | 1 | ... | ... | 1 |
| 31,000—31,999 | ... | . | ... | .. | .. | ... | .. | .. | 1 | 1 |
| Total | 379 | 367 | 370 | 335 | 382 | 371 | 486 | 427 | 405 | 3,522 |

Source: World Oil (February 15, 1975): 91.

Deep wells are either naturally flowing or pumped. Secondary techniques are not normally applied to the wells because of their extreme depth. Gas lift is the preferred method for pumping deep wells, largely because sucker rod strings long enough to reach the well bottom are unwieldly and will not function properly.

## 3. Environmental Impacts

### 3.1 Atmospheric Emissions

The only sources of atmospheric emissions associated with conventional recovery methods are the engines needed for artificial lift and for fluid injection. Gas powered engines could degrade air quality by generating $NO_x$ emissions. As a rule this is not a problem. Gas is used as a fuel when there is a convenient source nearby such as casinghead gas from the well itself or from a nearby field. In recent years, there has been a decrease in the use of gas as a fuel in favor of electricity, which is more universally available. In relatively developed, or urban areas, where air quality is very sensitive to incremental pollutant loadings, electric motors are also used.

The only prime movers used in primary production are associated with artificial lift equipment. Most of the production pumps are walking beams. These generally operate on electric motors in the 20 to 25 horsepower range. Maximum size of walking beam engines is about 90 horsepower.

Waterflooding requires injection pumps as well as production pumps. These pumps, as mentioned earlier, are driven by electric motors or by multi-cylinder gas engines. One engine is needed for each pump, and several pumps can be located at a single injection plant. Pumps require up to 300 brake horsepower, depending on the size of the pump and the operating rate. Several pumps can be clustered in a single location in order to provide a required flow rate. For example, in the Webster Field in Texas, three pumps with a total of 4,200 horsepower are used at a single plant injecting 50,000 barrels of water per day.[25] The large Wilmington Field in California uses 103 pumps in 19 injection stations to inject 1.5 million bbl/day of water. Twenty of the pumps are powered by natural gas; the rest are electric.[26]

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[25] Personal communication, Jack Coffman, Engineering Manager, Friendswood Production Office, Exxon Corporation, September 3, 1976.

Compressors used for gas injection also require prime movers. Electric motors and gas engines are both used, depending on the availability of gas and electricity. Compressors range in size from 200 to 4,000 horsepower. As is the case with water injection, several compressors are often coupled together to produce sufficient pressure and volume flow rates. The Webster Field has two separate compressor stations, each injecting into a single well. A total of 11 compressors requiring 7,000 horsepower are used to supply the gas at the necessary pressure of 2,100 psi; 40,000 MCF/day of methane are injected into the reservoir's gas cap.[27] All of the compressors in this field are natural gas powered.

The electric motors used to power production and injection pumps and gas compressors do not present an on-site environmental problem. Gas engines, on the other hand, do possess a potential for degrading air quality by generating various emissions, particularly oxides of nitrogen. The significance of the impact is determined mainly by the size and the spatial distribution of the engines. Problems associated with natural gas engines are discussed in Section IV.E.

### 3.2 Water Consumption

Waterflooding is the only conventional recovery technique that requires large volumes of water. The great bulk of injected water is treated salt water -- either produced water from the waterflood project itself or salt water obtained from wells drilled into nearby formations. Use of produced water for injection not only fulfills production requirements, it also ameliorates the brine disposal problem. Use of brine as the major injection water source is expected to continue as new waterflood projects are initiated in the future. Freshwater use is limited because in many cases it is unsuitable due to the mineralogy of the reservoir and because it is considerably more expensive. Other sources of water are being experimented with, but none have yet proved wholly successful. These include filtered and treated ocean water and secondary and tertiary sewage effluent.

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[26] "Water-Quality Control Presents Challenge in Giant Wilmington Field," 1976.

[27] Personal communication, Jack Coffman.

### 3.3 Brine Disposal

Disposal of brine produced along with the oil is a problem associated with all methods of oil recovery. The ratio of water produced to oil produced varies from well to well over an extremely wide range. In California's District 1 in 1974, the percentage of water in total production ranged from nearly 0 percent to almost 100 percent.[28] The amount of brine produced depends on the nature and origin of the producing formation and on the age of development. Brine disposal is treated in detail in Section IV.D.

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[28] California Division of Oil and Gas, 60th Annual Report of State Oil and Gas Supervisor.

## B. Offshore

### 1. Introduction

Oil produced at many platforms located in coastal waters is accompanied by water from the oil-containing reservoirs. This water, referred to variously as "produced water", "formation water", or "oilfield brine", contains high concentrations, relative to sea water or to water quality criteria, of certain ions such as sodium, calcium, and chloride, and low concentrations of a number of substances including oil hydrocarbons and a variety of trace metals. The produced water may be disposed of in various ways. California practice is to pipe all oilfield brine to onshore facilities for treatment and disposal onshore. In the Gulf of Mexico region, produced water is often separated from oil at the production platforms themselves and disposed of by being discharged directly into the adjacent waters. Production water from other platforms is, like California, piped ashore for treatment and disposal, sometimes by reinjection and sometimes by discharge into nearshore coastal waters. Since the oil hydrocarbons and trace metals contained in produced water may induce toxic (lethal and sublethal) effects on marine and estuarine organisms exposed to them, it is important to assess the impact of the discharge of produced water into coastal waters.

### 2. Offshore Production Data

There are three main drilling techniques currently used offshore. For waters up to about 350 feet the jack-up oil rig is used. This rig has collapsible legs which are retracted as it is floated out to the drilling site and which are then extended at the site until the platform is raised above the waves for drilling. The semisubmersible rig is used at depths up to 1,000 feet or more. This rig is held in place with large anchors and long mooring lines. For depths greater than 2,000 feet a drill ship is used. It is a nchored but additional stability is maintained from thrusters that compensate for winds and currents.[1]

After successful drilling, production platforms are erected. These must be attached to the bottom implying increases in complexity with water depth and sea condition. For coastal and relatively shallow waters, production wells are situated on individual platforms. The produced fluids from the wells may then be brought ashore or piped to a central platform facility for processing. All facilities required for recovery are on these platforms, including compressor stations for gas lift wells, water treatment facilities for waterflood projects, and separation and treatment facilities. The condition of the seas and climate also affect the design of the platform. Where seas are rough and the climate is severe enclosed platforms with extra structural support are necessary; in milder areas they are not.[2]

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[1] Massachusetts Institute of Technology, "Offshore Oil: Technology and Emotion," Technology Review 74(4) (February 1976).

Offshore oil production in the United States is currently concentrated in three main areas: the Gulf of Mexico adjacent to Louisiana and Texas, coastal California, and Cook Inlet, Alaska. Table IV-4 presents a list of the major producing offshore fields along with the number of wells for each field, 1975 oil production, and cumulative production.

### 3. Environmental Impacts

Statistics on the quantities of water produced along with the oil vary in detail and availability depending on location. The most complete records are those published by the Resources Agency of California, which in its Monthly Oil and Gas Production Report gives oil and water production for every field and area. Table IV-5 gives for each district the total number of barrels of oil and water, and percent produced water for February 1976. The Monthly Report also includes separate statistics for offshore production in state waters and in Federal OCS waters. The February 1976 figures are shown in Table IV-6. It will be seen from Tables IV-5 and IV-6 that produced water makes up a sizable proportion of the total production (oil and water). The smallest proportion is 51.7 percent for Federal OCS waters. This is perhaps due to the fact that production in Federal waters is the most recent, since in general water production increases with the age of the well.

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[2] U.S. Environmental Protection Agency, Development Document for Interim Final Effluent Limitations Guidelines and New Source Performance Standards for the Offshore Segment of the Oil and Gas Extraction Point Source Category, September 1975, pp. 20-21.

## TABLE IV-4

## MAJOR PRODUCING OFFSHORE FIELDS IN THE UNITED STATES

| STATE | FIELD DISCOVERY DATE | NO. WELLS | 1975 PRODUCTION (Million Barrels) | CUMULATIVE PRODUCTION (Million Barrels) |
|---|---|---|---|---|
| Alaska | Granite Point | 23 | 4 | 60 |
| | McArthur River | 57 | 41 | 294 |
| | Middle Ground Shoal | 35 | 8 | 96 |
| California | Dos Cuadras, 1960 | 123 | 14 | 116 |
| | Santa Ynez, 1970 | -- | -- | -- |
| | Huntington Beach, 1920 | 1,097 | 17 | 941 |
| | Wilmington, 1932 | 2,249 | 66 | 1,747 |
| Louisiana | Bay Marchand Bk. 2 (Incl. Onshore), 1949 | 195 | 22 | 452 |
| | Eugene Island Bk. 126, 1950 | 50 | 4 | 93 |
| | Eugene Island Bk. 330, 1971 | 136 | 28 | 68 |
| | Eugene Island Bk. 175, 1956 | 60 | 5 | 42 |
| | Eugene Island Bk. 276, 1964 | 60 | 4 | 51 |
| | Grand Isle Bk. 16, 1948 | 77 | 11 | 222 |
| | Grand Isle Bk. 43, 1956 | 220 | 17 | 101 |
| | Grand Isle Bk. 47, 1955 | 65 | 3 | 68 |
| | Main Pass Bk. 35, 1951 | 66 | 1 | 81 |
| | Main Pass Bk. 69, 1948 | 117 | 6 | 196 |
| | Main Pass Bk. 306, 1969 | 124 | 5 | 37 |
| | Ship Shoal Bk. 204, 1968 | 46 | 4 | 31 |
| | Ship Shoal Bk. 207, 1967 | 49 | 5 | 49 |
| | Ship Shoal Bk. 208, 1962 | 73 | 8 | 101 |
| | South Marsh Island Bk. 73, 1963 | 41 | 3 | 44 |
| | South Pass Bk. 24 (Incl. Onshore), 1950 | 434 | 13 | 384 |
| | South Pass Bk. 27, 1954 | 327 | 9 | 268 |
| | South Pass Bk. 62, 1965 | 61 | 5 | 54 |
| | South Pass Bk. 65, 1969 | 65 | 8 | 55 |
| | Timbalier Bay Bk. 21, 1959 | 169 | 6 | 165 |
| | West Delta Bk. 30, 1949 | 194 | 18 | 330 |
| | West Delta Bk. 58, 1964 | 70 | 9 | 47 |
| | West Delta Bk. 73, 1962 | 112 | 8 | 136 |

Source: Oil and Gas Journal (May 3, 1976).

## TABLE IV-5

## OIL AND PRODUCED WATER, FEBRUARY 1976, FOR CALIFORNIA PRODUCTION DISTRICTS

| DISTRICT NO. | TOTAL BARRELS OIL | TOTAL BARRELS WATER | PERCENT WATER |
|---|---|---|---|
| 1 | 9,469,155 | 64,917,636 | 87.3 |
| 2 | 2,099,116 | 5,886,624 | 73.7 |
| 3 | 2,335,113 | 17,532,790 | 88.2 |
| 4 | 9,571,425 | 59,592,329 | 86.2 |
| 5 | 859,333 | 6,346,717 | 88.1 |
| 6 | 27,533 | 209,752 | 86.5 |
| STATE TOTAL | 24,361,675 | 154,485,848 | 86.4 |

Source: Resources Agency of California, Department of Conservation, Division of Oil and Gas, Monthly Oil and Gas Production Report, Sacramento, Calif., February 1976.

## TABLE IV-6

## OFFSHORE PRODUCTION FOR CALIFORNIA, FEBRUARY 1976

| | BARRELS OIL | BARRELS WATER | PERCENT WATER |
|---|---|---|---|
| Coastal Region | 283,461 | 730,254 | 72.0 |
| Los Angeles Region | 4,580,964 | 24,747,568 | 84.4 |
| State Total | 4,864,425 | 25,477,822 | 84.0 |
| Federal OCS | 1,153,914 | 1,232,906 | 51.7 |

Source: Resources Agency of California, Monthly Oil and Gas Production Report, February 1976, p.17.

For the Gulf of Mexico production, such detailed figures do not appear to be available. Estimates can be developed from several sources, however. A recent study of hydrocarbons in Gulf of Mexico waters indicates a discharge of about 890,000 bbl/day ($15 \times 10^7$ liters/day) within the 3-mile limit and a discharge of about 275,000 bbl/day ($4.6 \times 10^7$ liters/day) into far offshore waters, that is, waters beyond the 3-mile limit.[3] The latter value is consistent with an estimate provided by the U.S. Geological Survey; they estimate that about 800,000 bbl/day of oil and about 600,000 bbl/day of water are produced beyond the 3-mile limit, and that about half of the water is shipped onshore for treatment and disposal.[4] Thus, about 300,000 bbl/day of produced water would be discharged into far offshore waters.

In Alaska, the percentage of produced water to total production of oil and water appears to be somewhat lower. The recent Draft Environmental Impact Statement for Lower Cook Inlet[5] gives a total of 651 million barrels of oil and 84 million barrels of water produced in the period of 7.5 years of commercial operation through 1974. Thus, produced water represents 11 percent of total fluid production.

Oilfield brines contain high concentrations of three principal cations -- sodium, magnesium, and calcium -- and one principal anion -- chloride. The high levels of these ions are responsible for the high salinity of most produced waters relative to seawater. The levels of these ions in brines and seawater are listed in Table IV-7. Although these ions are often present in large concentrations, it is important to note that the ratios of the concentrations of

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[3] W. Sackett and J. Brooks, "Origin and Distributions of Low Molecular Weight Hydrocarbons in Gulf of Mexico Coastal Waters," in Marine Chemistry in the Coastal Environment, ed. by T. Church, American Chemical Society Symposium Series 18, 1975.

[4] Personal communication, Mr. George Trussel, U.S. Geological Survey, Metairie, Louisiana, August 1976.

[5] Bureau of Land Management, Lower Cook Inlet Draft Environmental Impact Statement, Vol. 2, Alaska Outer Continental Shelf Office, Proposed Oil and Gas Lease Sale, 1976.

## TABLE IV-7

## MAJOR CATIONS AND ANIONS IN OFFSHORE OILFIELD BRINE

| ION | CONCENTRATION IN SEAWATER (ppm) | TYPICAL BRINE CONCENTRATION (ppm) |
|---|---|---|
| $Na^+$ | 10,500 | 40,000- 50,000 |
| $Ca^{++}$ | 1,350 | 2,500- 8,000 |
| $Mg^{++}$ | 400 | 500- 3,000 |
| $Cl^-$ | 19,000 | 50,000-100,000 |

Source: Energy Resources Company Inc., Benefits Study of Effluent Limitations for the Offshore Segment of the Oil and Gas Extraction Point Source Category, Draft Final Report, for the U.S. Environmental Protection Agency, August 1976, p. 3-2.

these ions in oilfield brines to their concentrations in seawater is of the order of only 5 or 10 to 1. Hence a dilution of 10 parts seawater to 1 part oilfield brine will bring the initially high concentrations of the major ions in produced water down very close to seawater concentrations. Since such a dilution is readily obtained in most forms of effluent discharge, the major ions present little cause for concern in discharges of oilfield brines into seawater.

The discharge of large quantities of oilfield brines into enclosed shallow nearshore bays or tidal creeks with low salinities may, of course, alter the ecology of the receiving waterbody since salinity is a key factor influencing the physiology of most organisms. A study[6] conducted by the Texas Parks and Wildlife Department on oil production operations in Chiltipin Creek in Texas noted a severe reduction in the white shrimp and blue crab populations. This was attributed to the hypersaline conditions produced by the discharge of large quantitites of oilfield brines. Such situations, however, are probably relatively uncommon just because they draw attention to themselves so readily. (In the case of Chiltipin Creek, discharge was eventually prohibited.) It appears safe to say that, barring situations where brine discharge to enclosed waterbodies is so great as to radically alter the salinity regime, the major ions present in produced water present little cause for environmental concern.

The principal causes for concern regarding the discharge of oilfield brines into coastal waters are the metals and oil hydrocarbons present in trace quantities. Trace metals present in oilfield brines include arsenic, cadmium, chromium, copper, lead, mercury, nickel, silver, and zinc. Table IV-8 presents the concentrations of these metals as measured in oilfield brines in various geographical regions. Also included in Table IV-8 are the seawater concentrations of these metals, their common chemical forms, and the EPA maximum acceptable concentrations. Further discussion of the potential impacts of trace metals and hydrocarbons discharged into coastal waters is contained in Appendix A.

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[6] T. Heffernan, "An Environmental Evaluation of the Tertiary Areas of Copano and St. Charles Bays," Part 1, Project Report, CE-1-1, An Ecological Evaluation of Some Tributaries of the Arkansas Bay Area (Rockport, Texas: Texas Parks and Wildlife Department, 1971).

## TABLE IV-8

## PRODUCED WATER CONSTITUENTS

| PARAMETER | SEAWATER[a] | | BRINES | | | | | | | WATER QUALITY CRITERIA LIMITS[f] | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | FORM | PPM | FORM[b] | LOUISIANA[c] (ppm) | ALASKA[d] (ppm) | CALIFORNIA[c] (ppm) | TEXAS[c] (ppm) | LA. CONCENT.[e] RATIO | AK. CONCENT.[e] RATIO | MAXIMUM ACCEPTABLE CONCENTRATIONS (ppm) | MINIMUM RISK THRESHOLD (ppm) |
| Ag | $AgCl_2^{--}$ | .0003 | | | <.010 | .03 | <.01-.10 | | <3.3 | .005 | .001 |
| As | $AsO_4H^{--}$ | .003 | $HAsO_2^-, H_2AsO_4^{--}$ | | <1-1.404 | .001-.08 | <.01-<.02 | | <333-468 | .05 | .01 |
| Cd | Cd++ | .00011 | $CdSO_4, CdCl_2$ | <.005-.675 | .001 | .02-.18 | <.02-.193 | <45-6136 | 736 | .01[h] | .0002 |
| CN | | | | <.01-.10 | | 0-.004 | | | | .01 | .005 |
| Cr | $CrO_4, Cr^{3+}$ | .00005 | | | <.01-.10 | .02-.04 | <.01-.23 | | <200-<200 | .1 | .05[i] |
| Cu | Cu++ | .003 | Org. Acid Salt | | .086 | .05-.116 | <.01-.38 | | 28.7 | .05[h] | .01 |
| Hg | $HgCl_2, HgCl_4^{--}$ | .00003 | | <.0995 | <.002-<.010 | .0005-.002 | <.0001-.13 | <16.7 | <4-<20 | .0001 | |
| Ni | Ni++ | .0054 | | | .005-.430 | .1-.29 | <.01-.44 | | .9-79.6 | .1 | .002 |
| Pb | Pb++, PbCl+ | .00003 | $Pb(HCO_3)_2$ | | <.01-.39 | 0-.28 | <.01-.22 | | <33.3-1300 | .05 | .01 |
| Zn | Zn++ | .01 | $ZnCl_2, ZnSO_4$ | | .277 | .05-3.2 | .1-.27 | | 27.7 | .1[h] | .02 |
| Ca | Ca++ | 400 | | 2,473[g] | 3,725 | | | 6.2 | 9.3 | | |
| Mg | Mg++ | 1,350 | Mg++ | 747[g] | 145.8 | | | .55 | .11 | | |
| Na | Na++ | 10,500 | Na+ | 44,607[g] | 7.650 | | | 4.2 | .73 | | |
| Cl | $Cl^-$ | 19,000 | $Cl^-$ | 61,000[g] | 13,953 | 17,230-21,000 | 42,000-62,000 | 3.2 | .73 | | |
| Oil & Grease | | | | 202[g] | 36 | 56-359 | | | | | |
| Phenols | | | | | 3.100 | .35-2.1 | 5.3 | | | | |
| BOD | | | | | 683 | 370-1,920 | 126-342 | | | | |
| COD | | | | | 1,671 | 400-3,000 | 182-582 | | | | |
| Total Solids | | 34,325 | | 110,200 | 23,842 | | | 3.2 | .69 | | |
| TDS | | | | 110,000 | 23,482 | 21,700-40,400 | 806-169,000 | | | | |
| TSS | | | | 22-390 | 99 | 1-60 | 12-656 | | | | |
| TOC | | | | 413 | | | | | | | |

NOTE: Footnotes are on the following page.

## FOOTNOTES TO TABLE IV-8

[a] M.G. Gross, *Oceanography: A View of the Earth* (Englewood Cliffs, N.J.: Prentice-Hall, 1972).

[b] Gene A. Collins, *Geochemistry of Oilfield Waters* (New York: Elsevier Scientific Publishing Co., 1975).

[c] U.S. Environmental Protection Agency, *Development Document for Interim Final Effluent Limitations Guidelines and New Source Performance Standards for the Offshore Segment of the Oil and Gas Extraction Point Source Category*, 1975.

[d] Values are averages of values from four permit application forms submitted to U.S. Army Corps of Engineers. See text.

[e] Concentration Ratio = (ppm Brine)/(ppm Seawater).

[f] Water Quality Criteria limits, October 1973, from Environmental Studies Board, U.S. Environmental Protection Agency - *Water Quality Criteria 1973*, 1973.

[g] Gene A. Collins, "Geochemistry of Some Petroleum Associated Waters from Louisiana," *U.S. Bur. Min. Rep. Invest.*, No. 7326, 1970.

[h] Synergistic effects have been observed when cadmium, copper, and zinc are present simultaneously. Under those conditions Maximum Acceptable Concentrations should be reduced by an order of magnitude.

[i] When oysters are present the Maximum Acceptable Concentration should be reduced to 0.0[illegible] ppm.

Source: Energy Resources Co. Inc., *Benefits Study of Effluent Limitations for the Offshore Segment of the Oil and Gas Extraction Point Source Category*, p. 3-6.

One conclusion emerging from the discussion given in Appendix A of the toxic effects of produced water constituents is that oilfield brines are not innocuous and cannot be regarded as merely concentrated seawater. The brines at the point of discharge contain toxic substances in concentrations more than sufficient to induce lethal and sublethal effects which are potentially damaging to the continued maintenance and survival of a considerable number of species. However, the fact that brine constituents can induce toxic effects does not in itself indicate the extent to which impacts can be expected to occur. To assess the extent of the impacts due to oilfield brine disposal requires a knowledge of how large a region of the receiving waters can be expected to be subjected to significant brine concentrations. The estimation of such impacted areas is a complex matter involving, as it does, the interaction of the brine discharge (rate of discharge and brine composition); properties of the receiving waters such as depth, area, current patterns, and tides; and the biota at the discharge location. Furthermore, there may be risks to human health due to the bioaccumulation of brine consituents in species destined for human consumption.

Appendix A makes such an assessment for several typical cases, as examples. It must be emphasized that these calculations are only examples; no quantitative assessment of the expected local impacts of any of the alternative scenarios can be made since there is no way of determining where new wells will be placed or where production from existing wells will be increased or decreased. Anticipating the production consequences of the alternative strategies (Chapter VI), the following general conclusions can be drawn. No impact relative to the Base Case, i.e., no production effects, would be expected along the East Coast (Region 11A). All of the strategies except for those involving stripper redefinition (IIIC) increase Gulf Coast (Region 6A) production by about 2 to 3 percent. The three combinations involving stripper redefinition increase offshore production by about 70,000 bbl/day or, equivalently, about 5 percent. All of the alternatives increase production along the California coast (Region 2A) by about 80 percent.

Present EPA regulations will not control any discharge other than oil and grease.[7] Control of oil and grease will limit but not prevent the discharge of hydrocarbons, toxic and otherwise.

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[7] U.S. Environmental Protection Agency, Development Document for Interim Final Effluent Limitations Guidelines and New Source Performance Standards for the Offshore Segment of the Oil and Gas Extraction Point Source Category, 1975.

The types of control devices necessary to meet the proposed EPA regulations will not remove dissolved materials, which include heavy metals and, unfortunately, many of the more toxic hydrocarbon species found in crude oil.[8]

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[8] Stephen F. Moore, "Towards a Model of the Effects of Oil on Marine Organisms," in Background Papers for a Workshop on Inputs, Fates and Effects of Petroleum in the Marine Environment, Vol. II, Ocean Affairs Board, National Academy of Sciences, 1973.

## C. Tertiary Recovery Methods

### 1. Steam Injection

### 1.1 Introduction

Tertiary oil recovery by cyclic and continuous steam injection is currently accounting for the bulk of thermal recovery production in the United States. The most recent survey[1] shows that more than 235,000 barrels of oil per day are being produced by some 54 active operations. Although operators were nearly unanimous in assessing their projects as either successful or promising, some operating problems mentioned involved sand control, water and low-sulfur fuel availability, and treatment problems arising from the production of stable emulsions.

These problems include several of the factors that are considered in the following sections in evaluating the local environmental impacts associated with this technology. Release of sulfur oxides to the atmosphere from the oil-fired steam boiler units is seen to be an acute consideration for sizeable projects, as is the availability of water for steam injection. Some water can be recycled through the reservoir after treatment to alleviate some of the fresh-water demand, but emulsions involving the produced water creates some additional problems. In any case, the environmental consequences of treatment and disposal of the produced water or brine must be examined.

Average rates of resource consumption are developed and environmental residuals are assessed in the following sections. Impacts of atmospheric releases are discussed, and those associated with water treatment and brine disposal are considered in Section IV.D. of this report.

### 1.2 Process Description

There are two operational variations of the steam injection process; steam soak and steam drive. In the first method, steam is injected for a relatively short period of time to heat up the formation, and normal recovery techniques are employed thereafter. The steam drive, on the other hand, employs a continuous injection of steam to enhance recovery at surrounding recovery sites (production wells). Table IV-9 displays the most recent listing of steam projects in the United States.

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[1] "U.S. Thermal Recovery Activity Growing Steadily," Production Report, Oil and Gas Journal 74 (14) (April 5, 1976): 108.

Thermally-enhanced oil recovery methods take advantage of two basic factors. These are the reduced oil viscosity at high temperatures and the mobility enhancement produced through steam distillation processes in the formation. Both of these mechanisms are particularly suited to reservoirs containing heavier crudes.

When a reservoir is undergoing a steam drive recovery, the steam saturated zone is approximately at the temperature of the injected steam. This zone moves oil to the production wells by steam distillation of the oil, solvent extraction, and a gas drive. As the steam cools and condenses, a zone of hot water is produced, and this floods the formation. Cyclic steam stimulation, however, requires no separate injection wells. Steam is injected into the reservoir through production wells for a period of 8 to 20 days and longer, depending on the reservoir characteristics and injection rates, and the wells are closed off to allow the heat to soak into the formation. This reduces the amount of initial heat loss that would otherwise take place as the hotter oil near the well bore is removed. Oil is then pumped for a period of several months, ranging from 4 to 11, until production declines below an economically acceptable level. The total cycle time is dependent upon the reservoir characteristics and the amount of oil-in-place. Table IV-10 shows production figures for nine typical steam soak projects in California, the site of virtually all present steam soak activity (see Table IV-9). The sensitivity of cycle time to the remaining oil-in-place is best seen in plots of oil production versus time since steaming, for several elapsed cycles (Figure IV-3).

The required resources for steam injection projects are fuel for the steam generators and a water source. Clearly, fuel availability problems are minimized where crude oil or gas from nearby operations is used, and decisions on fuel type are based on economic considerations. If the sulfur content of the produced crudes is sufficiently low to reduce the need for sulfur dioxide removal equipment, then this is the most cost-effective fuel. In general, projects have used natural gas, crude oil, and processed fuel oil in their boilers.

Water usage varies from project to project, and is best expressed in terms of an average ratio of steam injected

# TABLE IV-9

## CURRENT STEAM INJECTION PROJECTS IN THE UNITED STATES

| FIELD | STATE | COUNTY | OPERATOR | AREA (ACRES) | NUMBER WELLS PROD. | NUMBER WELLS INJ. | DEPTH (FT.) | PROJECT MATURITY | ENHANCED PROD. (bn/d) | PERCENT OF FUEL SULFUR |
|---|---|---|---|---|---|---|---|---|---|---|
| Steam Soak | | | | | | | | | | |
| Coalinqua | CA | Fresno | Shell | 2,520 | 385 | - | 900-2,800 | HF | 3,900 | .25 |
| W. Coalinqua | CA | Fresno | Socal | 1,280 | - | - | 12,000 | 90% compl. | - | .55 |
| Asphalto | CA | Kern | Getty | 120 | 4 | - | 14,000 | HF | 100 | .42 |
| S. Belridge | CA | Kern | McCulloch | 100 | - | - | 800 | HF | - | .23 |
| Cymric | CA | Kern | Getty | 70 | 22 | - | 1,000 | HC | 500 | 1.16 |
| Cymric | CA | Kern | Gulf | - | 8 | - | 1,000 | - | - | 1.16 |
| Cymric | CA | Kern | Mobil | 170 | 46 | - | 600-900 | 32% compl. | 400 | 1.16 |
| Cymric | CA | Kern | Socal | 700 | - | - | 1,000 | 60% compl. | - | 1.16 |
| Edison | CA | Kern | Exxon | 1,100 | 75 | - | 1,100 | HF | 600 | .20 |
| Kern Front | CA | Kern | ARCO | 160 | 56 | - | 1,600 | - | - | .85 |
| Kern Front | CA | Kern | Getty | 1,080 | 132 | - | 2,300 | HF | 1,676 | .85 |
| Kern Front | CA | Kern | Mobil | 600 | 100 | - | 1,800 | JS | 450 | .85 |
| Kern Front | CA | Kern | Socal | 640 | - | - | 2,400 | 75% compl. | - | .85 |
| Kern River | CA | Kern | Chans.West. | 240 | 172 | | 100-800 | - | 100 | 1.19 |
| Kern River | CA | Kern | Getty | 3,000 | 1,271 | - | 900 | HC | 14,500 | 1.19 |
| Kern River | CA | Kern | Getty | 9 | 3 | - | 900 | HF | 10 | 1.19 |
| Kern River | CA | Kern | Shell | 1,300 | 443 | - | 300-1,300 | HF | 9,000 | 1.19 |
| Kern River | CA | Kern | Socal | 1,400 | - | - | 1,000 | 85% compl. | - | 1.19 |
| Lost Hills | CA | Kern | ARCO | 15 | 7 | - | 500 | HC | - | .33 |
| Lost Hills | CA | Kern | Getty | 150 | 61 | - | 500 | HF | 500 | .33 |
| Lost Hills | CA | Kern | Gulf | - | 43 | - | 200-400 | - | - | .33 |
| Lost Hills | CA | Kern | Gulf | 1 | 3 | - | 700 | JS | - | .33 |
| McKittrick | CA | Kern | Getty | 300 | - | - | 1,200 | HF | 7,600 | .96 |
| McKittrick | CA | Kern | Getty | 3 | - | - | 1,200 | HC | - | .96 |
| McKittrick | CA | Kern | Occidental | 46 | - | - | 900 | HF | - | .96 |
| McKittrick | CA | Kern | Socal | 120 | - | - | 820 | 90% compl. | - | .96 |
| Midway Sunset | CA | Kern | ARCO | 1,000 | 816 | - | 1,000-2,500 | - | - | .94 |
| Midway Sunset | CA | Kern | Chans.West. | 1,970 | 821 | - | 400-1,000 | - | 20,000 | .94 |
| Midway | CA | Kern | Getty | 215 | 21 | - | 850-1,150 | HF | 390 | - |
| Midway | CA | Kern | Getty | 125 | 71 | - | 1,200 | HF | 2,100 | - |
| N. Midway | CA | Kern | Getty | 155 | 70 | - | 1,400 | HF | 1,800 | - |
| Midway | CA | Kern | Getty | 86 | 16 | - | 1,800 | HF | 60 | - |
| Midway Sunset | CA | Kern | Getty | 35 | 44 | - | 1,700 | JS | 2,150 | .94 |
| Midway Sunset | CA | Kern | Mobil | 350 | 200 | 0 | 1,000 | HF | 3,500 | .94 |
| Midway Sunset | CA | Kern | Mobil | 950 | 50 | 0 | 950 | 40% compl. | 504 | .94 |
| Midway Sunset | CA | Kern | McCulloch | 60 | 117 | - | 1,100 | 60% compl. | 3,000 | .94 |
| Midway Sunset | CA | Kern | Occidental | 23 | - | - | 1,000 | HF | - | .94 |
| Midway Sunset | CA | Kern | Shell | 565 | 530 | - | 600-1,900 | HF | - | .94 |
| Midway Sunset | CA | Kern | Socal | 160 | - | - | 1,200 | HF | - | .94 |
| Midway Sunset | CA | Kern | Sun | 226 | 158 | cylic | 1,000-1,500 | HF | 4,300 | .94 |
| Pose Creek | CA | Kern | Getty | 84 | 14 | - | 2,000 | JS | 120 | - |
| Pose Creek | CA | Kern | Socal | 240 | - | - | 2,500 | 80% compl. | - | - |
| Santiago | CA | Kern | Gulf | - | 18 | - | 550-1,250 | - | - | - |
| S. Belridge | CA | Kern | Socal | 150 | - | - | 550-1,250 | HF | - | - |
| S. Belridge | CA | Kern | McCulloch | 100 | 40 | - | 800 | HF | 150 | .25 |
| Huntington Beach | CA | Orange | Burmah | 50 | 9 | 4 | 2,000 | HF | 200 | 1.57 |
| Huntington Beach | CA | Orange | Burmah | 710 | 40 | 0 | 2,000 | HF | 1,500 | 1.57 |
| Huntington Beach | CA | Orange | Socal | 300 | - | - | 2,000 | 60% compl. | - | 1.57 |
| Yorba Linda | CA | Orange | Gulf | - | 86 | - | 200-2,000 | - | - | 1.86 |
| Yorba Linda | CA | Orange | Shell | 100 | 292 | 23 | 400-830 | HF | 8,500 | 1.86 |

# TABLE IV-9 (CONT.)

| FIELD | STATE | COUNTY | OPERATOR | AREA (ACRES) | NUMBER WELLS PROD | INJ. | DEPTH (FT.) | PROJECT MATURITY | ENHANCED PROD. (bo/d) | PERCENT OF FUEL SULFUR |
|---|---|---|---|---|---|---|---|---|---|---|
| Cat Canyon | CA | Santa | Conoco | 650 | 130 | - | 3,000 | HF | 4,030 | 5.07 |
| Cat Canyon | CA | Barbara | | | | | | | | |
| Cat Canyon | CA | " | Getty | 1,700 | 100 | 9 | 2,100 | HF | 2,090 | 5.07 |
| Cat Canyon | CA | " | Getty | 300 | 13 | 0 | 3,000 | HF | 163 | 5.07 |
| White Castle | LA | Iberville | Shell | 57 | 2 | - | 1,350 | JS | 200 | .10 |
| White Castle | LA | Iberville | Shell | 37 | 2 | - | 1,000 | JS | 200 | .10 |
| Anderson Ranch | TX | Zavala | Exxon | 2 | 1 | 1 | 525 | Term. 5/75 | 2-190 | - |
| Uvalde | TX | Zavala | Gulf | 3 | - | - | 300 | Term. 8/75 | - | - |
| Steam drive | | | | | | | | | | |
| Smackover | AR | Ouachita | Phillips | 985 | 120 | 9 | 1,920 | HF | 1,300 | 2.10 |
| Belridge | CA | Kern | Mobil | 2,381 | 250 | 18 | 1,000 | 14% compl. | 5,400 | .23 |
| Coalinga | CA | Fresno | Shell | 700 | 104 | 23 | 1,500 | NC | 1,300 | .25 |
| W. Coalinga | CA | Fresno | Socal | 30 | - | - | 1,200 | 40% compl. | - | .55 |
| Cymric | CA | Kern | Socal | 18 | 21 | 9 | 900 | JS | 400 | 1.16 |
| Kern River | CA | Kern | Chans.West | 15 | 17 | 11 | 660 | JS | - | 1.19 |
| Kern River | CA | Kern | Getty | 2,000 | 1,373 | 781 | 900 | - | 32,200 | 1.19 |
| Kern River | CA | Kern | Getty | 22.5 | 16 | 9 | 900 | HF | - | 1.19 |
| Lost Hills | CA | Kern | Getty | 11 | 9 | 6 | 200 | JS | - | .33 |
| Kern River | CA | Kern | Chans.West | 1 1/8 | 4 | 19 | 700 | JS | 270 | 1.19 |
| Kern River | CA | Kern | Socal | 1,400 | - | - | 1,000 | 85% compl. | - | 1.19 |
| N.E. McKittrick | CA | Kern | Socal | 95 | 23 | 16 | 1,200 | JS | 300 | .96 |
| Midway Sunset | CA | Kern | ARCO | 6 | 12 | 2 | 1,000-2,500 | HF | - | .94 |
| Midway Sunset | CA | Kern | ARCO | 3.7 | 7 | 1 | 2,000 | HF | - | .94 |
| Midway Sunset | CA | Kern | ARCO | 12.2 | 10 | 3 | 2,500 | HF | - | .94 |
| Midway Sunset | CA | Kern | Chans.West | 20 | 16 | 6 | 1,500 | HF | 990 | .94 |
| Midway Sunset | CA | Kern | Chans.West | 1 1/4 | 4 | 1 | 1,200 | Term. 2/76 | - | .94 |
| Midway Sunset | CA | Kern | Chans.West | 5 | 4 | 1 | 1,000 | JS | 95 | .94 |
| Midway Sunset | CA | Kern | Chans.West | 6.5 | 8 | 4 | 600 | JS | 80 | .94 |
| Midway Sunset | CA | Kern | Shell | 120 | 51 | 17 | 1,200 | - | 3,000 | .94 |
| Midway Sunset | CA | Kern | Socal | 21 | 15 | 6 | 1,200 | JS | 0 | .94 |
| Midway Sunset | CA | Kern | Texaco | 10 | 8 | 1 | 1,200 | HF | 101 | .94 |
| Mount Poso | CA | Kern | Shell | 300 | 60 | 11 | 1,800 | - | 8,000 | .68 |
| San Ardo | CA | Monterey | Mobil | 3,041 | 850 | 40 | 2,100&2,300 | 23% compl. | 8,000 | 2.25 |
| San Ardo | CA | Monterey | Texaco | 1,725 | 192 | 39 | 2,200 | HF | 22,900 | 2.25 |
| San Ardo | CA | Monterey | Texaco | 80 | 29 | 2 | 1,900 | HF | 100 | 2.25 |
| Brea-Olinda | CA | Orange | Chans.West | 15 | 19 | 1 | 800 | JS | 127 | .75 |
| Caddo Pine Isl. | LA | Caddo | Texaco | 36 | 4 | 1 | 800 | JS | 9 | .37 |
| Port Barre | LA | St. Landry | Texaco | 6.4 | 4 | 1 | 1,450 | JS | 9 | .45 |
| Slocum | TX | Anderson | Shell | 258 | 259 | 49 | 520 | NC | 1,900 | <.10 |
| Slocum | TX | Anderson | Texaco | 18 | 15 | 3 | 500 | Term. 74 | 29 | <.10 |
| Toborg | TX | Pecos | Gulf | 20 | 9 | 4 | - | JS | 30 | - |
| Winkleman Dome | WY | Fremont | Amoco | 100 | 21 | 13 | 1,225 | HF | 720 | 2.59 |

HF = half finished; NC = nearing completion; JS = just started; Term. = terminated.

Source: "U.S. Thermal Recovery Activity Growing Steadily," Production Report, Oil and Gas Journal 74(14) (April 5, 1976).

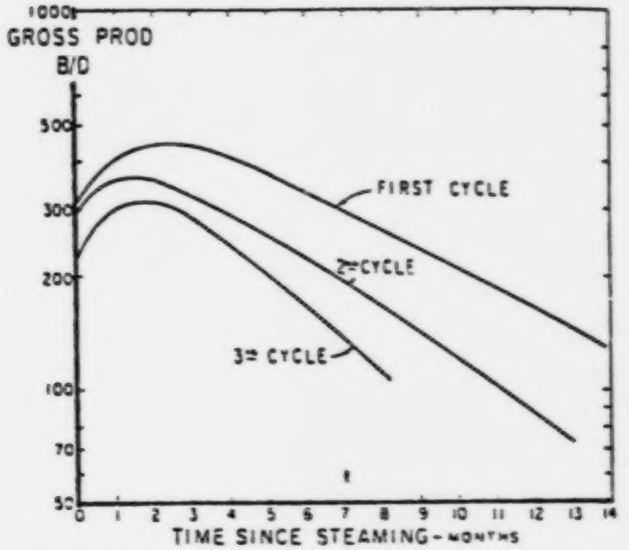
## TABLE IV-10

## SUMMARY OF TYPICAL WELL PERFORMANCE - STEAM SOAK OPERATIONS IN VARIOUS FIELDS OF CALIFORNIA

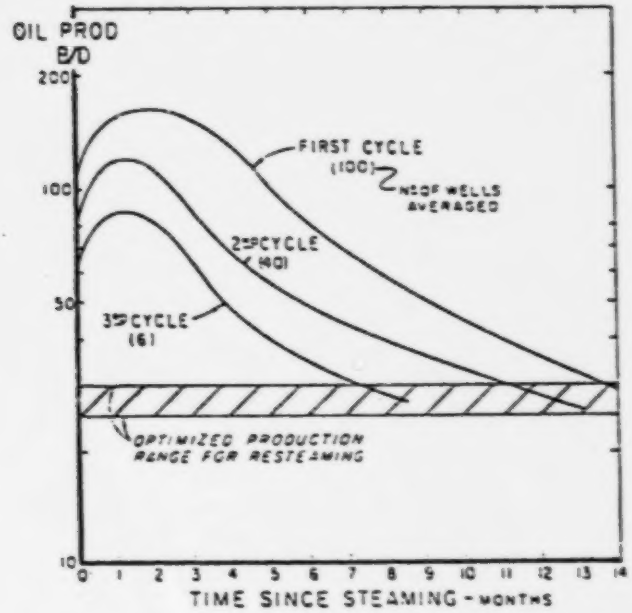
| FIELD | ZONE | STEAM INJECTED TOTAL (bbl) | OIL RECOVERED TOTAL (bbl) | STEAM OIL[1] RATIO (bbl/bbl) | CYCLE PERIOD (MONTHS) |
|---|---|---|---|---|---|
| Huntington Beach | TM | 4,500 | 29,000 | .15 | 15 |
| Kern River | China | 4,400 | 11,600 | .38 | 6 |
| Midway-Sunset | Potter (A) | 6,000 | 9,240 | .65 | 5 |
| Kern River | Kern River | 6,500 | 4,730 | 1.37 | 5 |
| Coalingua | Temblor | 9,000 | 4,300 | 2.08 | 5 |
| Midway-Sunset | Tulare | 12,000 | 4,640 | 2.63 | 6 |
| Midway-Sunset | Potter (B) | 7,700 | 3,000 | 2.56 | 4 |
| White Wolf | Reef Ridge | 14,000 | 6,750 | 2.08 | 4 |
| Poso Creek | Etchegoin | 6,700 | 2,660 | 2.5 | 6 |

[1] Steam volume reported in equivalent barrels of water.

Source: J. Burns, "A Review of Steam Soak Operations in California," in Thermal Recovery Techniques, SPE Reprint Series No. 10, 1972, p. 265.



AVERAGE CYCLIC GROSS PRODUCTION



PRODUCTION RESPONSE BY CYCLES

Figure IV-3. These are plots of well recovery response to several steam soak cycles. (R.H. Adams, and A.M. Khan, "Cyclic Steam Injection Projects Performance Analysis and Some Results of a Continuous Steam Displacement Pilot," in Thermal Recovery Techniques, Reprint Series No. 10, 1972, p. 276.)

(expressed as equivalent barrels of water) to oil produced. Steam drive projects are easiest to gauge in this way because steam injection is a fairly constant parameter over the process life. The ratio gradually increases as production falls off due to depletion, so a cumulative assessment of this quotient yields the best representative figure. Table IV-11 summarizes a number of projects of varying size and location. The quotients listed vary over a fairly small range with an average value of 5.2 barrels of water as steam per barrel of oil produced. The extreme value of 6.7 bbl/bbl registered for the Brea-Olinda project may be used as a worst case water consumption rate.

The steam soak projects produce oil over a much longer time interval than that which is needed for injecting the steam. Because of the differences in time periods, a straight ratio of water injected as steam to oil produced must be carefully interpreted. Table IV-10 presents these quotients for typical wells in nine California projects. The range of values for this process is a good deal wider than those associated with the steam drive process.

### 1.3 Environmental Impacts

The principal potential environmental impacts associated with steam injection production methods arise from emission of atmospheric pollution from steam-raising boilers, reinjection and disposal of produced water, freshwater consumption as boiler feedwater, and spills from operations in general. Produced water and spill-derived problems are common to all production technologies and are discussed in a later section (IV.D).

#### 1.3.1 Atmospheric Emissions and Effects

Steam raising in oil fields is carried out in boilers specially designed for this application. Pollutants are generated in the combustion process and are emitted in the exhaust or flue gas stream. Most oilfield boilers are equipped with short or stub stacks, which, as will be shown in the discussion immediately following, may lead to quite large ground-level pollutant concentration in the vicinity of the operating site. The character of the emissions and impact depends on the fuel fired under the boiler, the size of the unit, the stack configuration, and the local meteorological conditions.

## TABLE IV-11

## SUMMARY OF TYPICAL STEAM DRIVE PROJECT WATER USE

| FIELD | STATE | PATTERN SIZE (ACRES) | PATTERN TYPE | WATER INJECTION/OIL PRODUCED (bbl/bbl) |
|---|---|---|---|---|
| Kern River | California | 2.5 | Nor. 5-spot | 4.6 |
| Huntington Beach | California | 2 - 3 | Irreg. | 5.0 |
| Slocum Field | Texas | 5.65 (each) | 7, 13-spots | 6.25[1] |
| Inglewood | California | 2.6 | Inv. 6-spot | 3.7 |
| Winkleman Dome | Wyoming | 53 (total) | 6, 5-spots | 5.9 |
| Brea-Olinda | California | ∿ 29 | Irreg. | 6.7 |
| Smockover | Arkansas | 22 | Inv. 5-spot | 4.1 |
| E. Coalinqua | California | 530 (total) | Irreg. 5-spots | 4.0 |
| Holman Ranch | Texas | 2.5 | Inv. 5-spot | 5.9 |
| Kern River[2] | California | 61 (total) | 10, Inv. 7-spots | 5.8 |

[1] Revised data; based on Oil and Gas Journal (April 5, 1976): 110-113.

[2] T.R. Blevins, R.H. Billingsley, "The Ten-Pattern Steamflood, Kern River, California," Journal of Petroleum Technology, December 1975.

Source: S.M. Farouq Ali, "Current Status of Steam Injection as a Heavy Oil Recovery Method," Journal of Canadian Petroleum Technology, January-March, 1974.

The major potential environmental impact of the emissions is adverse health effects in humans. The National Ambient Air Quality Standards have been established to protect against adverse health effects. Expansion of steam injection projects under any of the alternative price policies would only be allowed provided that the incremental addition to existing pollutant concentrations would not cause the standards to be exceeded.

In some parts of California, standards for particulates, nitrogen oxide and oxidants are already exceeded. In these so-called non-attainment regions, new sources meeting certain size criteria cannot, in general, be developed. Depending on the policy yet to be established by EPA and local environmental control agencies, steam injection project boilers may be constrained. The size of boiler used in the field is quite small compared to industrial and utility boilers and is smaller than the minimum size governed by EPA New Source Performance Standards. It is, thus, possible that oil-field boilers will not be regulated under non-attainment restrictions, unless, of course, local conditions due to their emissions would exceed any air quality standard.

The significant deterioration provisions of the Clean Air Act may further restrict development. These provisions, still in an evolutionary stage, set limits on the incremental increase in atmospheric concentration in areas where existing levels are currently below the standards. It is not clear at this time what limits will apply to those regions of the United States where steam injection is most likely to be used, nor is it clear that the significant deterioration regulations will apply to sources as small as oil-field boilers.

The analysis that follows provides estimates of the emissions of sulfur dioxide ($SO_2$), nitrogen oxides ($NO_x$) and particulate matter (PM) from different size boilers and for different fuels. Estimates of worst-case ground-level concentrations are then made for a small- and a large-scale project.

Steam boilers vary in size from 5 to 500 million Btu per hour, and run on either gas, crude oil, or refined fuel oil (residual). The units most commonly in use are the 20 MMBtu/hr and 50 MMBtu/hr. Table IV-12 displays typical emissions rates for these two units when run on crude oil, residual oil, and natural gas. These rates were derived by assuming a thermal efficiency of 89 percent for the oil-fired boilers, and 80 percent for the gas boilers. The 80 percent figure for gas represents a very conservative estimate of efficiency and was used to preclude underestimation of the

## TABLE IV-12

## EMISSION RATES OF POLLUTANTS FROM BOILERS IN USE IN THE UNITED STATES[1]

| | CRUDE OIL[2] | | RESIDUAL OIL[3] | | NATURAL GAS[3] | |
|---|---|---|---|---|---|---|
| | 20 MMBtu/hr | 50 MMBtu/hr | 20 MMBtu/hr | 50 MMBtu/hr | 20 MMBtu/hr | 50 MMBtu/hr |
| $SO_2$ (gm/s) | 2.98S[4] | 7.37S | 2.91S | 7.24S | .0018 | .0045 |
| $NO_x$ (gm/s)[5] | 1.33 | 3.29 | 1.11 | 2.76 | .37-.70 | .92-.74 |
| PM (gm/s) | .22 | .55 | .24 | .60 | .045 | .113 |
| HC (gm/s) | .04 | .11 | .019[6] | .046[6] | .0091[6] | .023[6] |
| CO (gm/s) | .01 | .02 | .093 | .23 | .052 | .129 |

[1] 20 MMBtu/hr and 50MMBtu/hr are the unit sizes most commonly employed in the United States.

[2] Energy Resources Company Inc., Potential Environmental Consequences of Tertiary Oil Recovery, July 1976, p. 173.

[3] U.S. Environmental Protection Agency, Compilation of Air Pollutant Emission Factors, Report No. AP-42, April 1973 (supplement 6), p. 1.3-2.

[4] S = percent sulfur content of fuel by weight.

[5] Oxides of nitrogen as $NO_2$.

[6] Total hydrocarbons as $CH_4$.

$NO_x$ impact of these boilers. However, comparing the resultant $NO_x$ emission rate for the gas boilers with that from the oil burners shows these emissions to be substantially smaller.

The crude oil boilers were characterized by actual data gathered from boiler manufacturers and users in the field,[2] while the other two were taken from estimated factors contained in the EPA report on air pollution emission factors (AP-42). Table IV-13 compares these two sources for the residual fuel oil boilers. Apparently the actual boilers in use at steam injection projects are somewhat cleaner than expected with respect to carbon monoxide as the carbon monoxide emissions from the crude-burning boilers are nearly an order of magnitude smaller than the emissions from the other two boiler types. It is assumed that similar reductions in these emissions from residual oil and gas-fired boilers may be expected, so that all three boiler types may be assessed together. Air quality patterns associated with a crude oil-fueled steam injection project are considered to be representative of those patterns induced by a similar project using a residual fuel oil and are certainly more severe than air quality estimates pertaining to a gas-fired project.

Overall pollutant loading of a region can be indicated through the use of an emission per barrel of oil recovered indicator. These quotients are calculated in units of tons of pollutant per barrel of oil produced (ton/bbl) as follows. The first column of Table IV-13 gives an emission rate for $NO_x$ from a crude oil-fired boiler of 3.02 lb per barrel of crude consumed. One barrel of crude produces 6.447 million Btu of heat energy, of which 89 percent is utilized in producing steam. This means that there are $5.74 \times 10^6$ Btu of energy available per barrel of crude oil.

Furthermore, if 80 percent quality steam is produced in the range 1,000 to 2,000 psia, an average of 1,010 Btu per pound of water is needed. This is equivalent to $0.354 \times 10^6$ Btu per barrel of water converted. The average water to produced oil ratio for a steam drive project is 5.2 bbl/bbl (Section IV.C.1.2). All of these numbers are combined to give:

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[2] Energy Resources Co. Inc., Potential Environmental Consequences of Tertiary Oil Recovery, Final Report, for the U.S. Environmental Protection Agency, July 1976, p. 51.

## TABLE IV-13

## COMPARISON OF EMISSION RATES PER BARREL BURNED AS DETERMINED BY EPA DOCUMENT AP-42 AND THOSE DETERMINED BY ON-SITE MEASUREMENTS

| | CRUDE[1] (lb/bbl) | RESIDUAL[2] (lb/bbl) |
|---|---|---|
| $SO_2$ | 6.8S[3] | 6.6S[3] |
| $NO_x$ (as $NO_2$) | 3.02 | 2.52 |
| PM | .5 | .546 |
| HC | .1 | .042[4] |
| CO | .02 | .21 |

[1] Energy Resources, Potential Environmental Consequences of Tertiary Oil Recovery, 1976, p. 173.

[2] U.S. Environmental Protection Agency, Compilation of Air Pollutant Emission Factors, Report No. AP-42, 1973.

[3] Percent sulfur.

[4] Total hydrocarbons as $CH_4$.

$$(5.2\ \frac{\text{bbl water}}{\text{bbl oil}}) \times (0.354\ \frac{10^6\ \text{Btu}}{\text{bbl water}}) \times (\frac{1\ \text{bbl crude}}{5.74\ 10^6\ \text{Btu}})$$

$$\times (\frac{3.02\ \text{lb NO}_x}{\text{bbl crude}}) = 0.969\ \text{lb NO}_x/\text{bbl oil}$$

$$\text{or}\ \ 4.8 \times 10^{-4}\ \text{ton NO}_x/\text{bbl oil (for crude oil as fuel)}$$

This value can now be used to derive emission coefficients for all of the other pollutants and for other fuels by using the corresponding ratios of emission rates from Tables IV-12 and IV-13. The resulting emission coefficients for an average steam drive project are listed in Table IV-14. The first column values are generated from the oxides of nitrogen calculation and Table IV-13. The other two columns are calculated using the 20 MMBtu/hr values of $NO_x$ release from Table IV-12 to obtain values for $NO_x$ production when burning residual oil or natural gas. The other pollutants then follow. The use of Table IV-12 automatically accounts for the variations in thermal values between fuels, as well as the assumed boiler efficiency and pollutant production rates. Brackets around the values for carbon monoxide when burning residual fuel oil and natural gas serve to remind the reader that data from boiler manufacturers and actual field operation of the crude-fired boilers indicate that these boilers are cleaner than expected when compared to the broad estimates taken from AP-42.

Should it be desirable to use similar emission coefficients for the cyclic steam process, then the appropriate values may be obtained by multiplying those in Table IV-14 by the ratio of the average values of SOR (cyclic)/SOR (drive) or 0.308, and the corresponding emission coefficients are reported in Table IV-15.

In order to relate emission rates to ambient air quality, some assumptions must be made about the configuration of the sources of the release. Fields undergoing steam injection generally have more than one boiler unit operating at any one time, with larger projects having correspondingly larger number of boilers. Another study[3] considered the range

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[3] Energy Resources Co. Inc., Potential Environmental Consequences of Tertiary Oil Recovery, pp. 165-170.

## TABLE IV-14

## EMISSION COEFFICIENTS PER BARREL RECOVERED FOR AVERAGE[1] STEAM DRIVE PROJECTS

| | CRUDE OIL (ton/bbl) | RESIDUAL OIL (ton/bbl) | NATURAL GAS (ton/bbl) |
|---|---|---|---|
| $SO_2$ | $1.09 \times 10^{-3}$ S[2] | $1.06 \times 10^{-3}$ S[2] | $6.5 \times 10^{-7}$ |
| $NO_x$ (as $NO_2$) | $4.84 \times 10^{-4}$ | $4.04 \times 10^{-4}$ | $2.5 \times 10^{-4}$ |
| PM | $8.0 \times 10^{-5}$ | $8.8 \times 10^{-5}$ | $1.6 \times 10^{-5}$ |
| HC | $1.6 \times 10^{-5}$ | $6.7 \times 10^{-6}$ [3] | $3.3 \times 10^{-6}$ [3] |
| CO | $3.2 \times 10^{-6}$ | $(3.4 \times 10^{-5})$ | $(1.9 \times 10^{-5})$ |

[1] Worst case values are obtained by multiplying by 1.29.

[2] Percent sulfur.

[3] Total hydrocarbons as $CH_4$.

NOTE: Maximum values quoted for $NO_2$ release were used in deriving the above figures.

## TABLE IV-15

## LONG-TERM EMISSION COEFFICIENTS FOR AVERAGE[1] CYCLIC STEAM PROJECTS

| | CRUDE OIL (ton/bbl) | RESIDUAL OIL (ton/bbl) | NATURAL GAS (ton/bbl) |
|---|---|---|---|
| $SO_2$ | $3.36 \times 10^{-4}$ S [2] | $3.26 \times 10^{-4}$ S [2] | $2.00 \times 10^{-7}$ |
| $NO_x$ (as $NO_2$) | $1.49 \times 10^{-4}$ | $1.24 \times 10^{-4}$ | $7.70 \times 10^{-5}$ |
| PM | $2.46 \times 10^{-5}$ | $2.7 \times 10^{-5}$ | $4.93 \times 10^{-6}$ |
| HC | $4.93 \times 10^{-6}$ | $2.06 \times 10^{-6}$ [3] | $1.02 \times 10^{-6}$ [3] |
| CO | $9.86 \times 10^{-7}$ | $(1.05 \times 10^{-5})$ | $(5.85 \times 10^{-6})$ |

[1] Worst case values are obtained by multiplying by 1.64.

[2] Percent sulfur.

[3] Total hydrocarbons as $CH_4$.

of steam drive developments across the country and chose typical operating parameters representative of a large field development, such as the ones in operation in the Kern River area of California, and a small field development, typified by the Winkleman Dome project in Wyoming.

The large development case was synthesized from an analysis of major oil fields in California corrected for skew in the size distribution attributable to very large fields (greater than 13,000 acres). A typical field of 5,760 acres with nine sections of 640 acres each was chosen; its configuration is a 3-mile by 3-mile square, containing 36 20-MMBtu/hr boilers, and 72 50-MMBtu/hr boilers. The small development covers an area of 200 acres, and contains 2 50-MMBtu/hr units.

Table IV-16 shows the maximum predicted concentration of sulfur dioxide from the large field case located in central California as calculated using EPA's CRSTER model. This model predicts the worst case or maximum concentration for short-term averaging periods (3 hour or 24 hour) as well as generating an estimate of annual average concentrations. The values presented for $NO_x$ and particulates were derived from the $SO_2$ estimates by simple proportion.

TABLE IV-16

ESTIMATED MAXIMUM FIELD CALCULATIONS OF THE THREE MAJOR POLLUTANTS FROM THE SMALL AND LARGE AGGREGATES OF STEAM BOILERS

(These values are for crude oil boilers using 1.23 percent sulfur fuel.)

| | $SO_2$ ($\mu g/m^3$) | | | $NO_x$ (est.) ($\mu g/m^3$) | | | PM (est.) ($\mu g/m^3$) | | |
|---|---|---|---|---|---|---|---|---|---|
| | NAAQS | SMALL | LARGE | NAAQS | SMALL | LARGE | NAAQS | SMALL | LARGE |
| Annual | 80 | 13.5 | 140 | 100 | 4.9 | 62 | 75 | 0.8 | 10.3 |
| 24-Hour | 365 | 91 | 640 | - | 33 | 205 | 260 | 5.5 | 34 |
| 3-Hour | 1,300 | 529 | 662 | - | 192 | 295 | - | 32 | 49 |

Similar ambient concentrations can be computed for residual fuel oil and natural gas boilers through the use of the emission rates found in Table IV-12. Hydrocarbon and carbon monoxide emissions are so small that their impact on ambient air quality is insignificant.

Maximum ambient concentration calculations for the small development case, where 1.23 percent sulfur crude is assumed, showed no violations of the national standards. Further proportional estimates for particulates and $NO_x$ confirmed that these too were considerably below the regulatory level (see Table IV-16).

The large development case results indicate that, under the assumptions used, the $SO_2$ annual and 24-hour standards could be exceeded. If this were the case, the boilers would not be permitted to operate without some means of control, such as burning lower sulfur content oil or employing scrubbers. The peak concentrations from oilfield boilers occur fairly close to the units and in many cases would fall at locations within the field boundaries. Under those circumstances, the EPA would not consider the standard to be exceeded as the points fall within the property fence line. Those working within the field would, in that case, be subjected to exposures, during working hours, possibly exceeding standards.

Some means of abatement would be needed at many sites, since the sulfur content associated with steam injection in many fields is sufficiently high to cause problems meeting standards. Table IV-9 included representative analyses of fuel sulfur content[4] for many of the fields under development. Regions of acute ambient $SO_2$ problems would probably demand highly restrictive abatement procedures. However, most regions may require only a modest investment in boiler configuration changes to increase effective plume release heights and thereby relieve the maximum ground level impacts. Use of sulfur dioxide scrubbers would represent a more costly approach to the abatement problem.

While the discussion so far is focused on emissions and associated air quality levels, the impact of concern is human health. Appendix K contains some data pertinent to the relationship between $SO_2$ and health. The statutory basis of the air quality standards contains the implicit assumption of a threshold below which no adverse health effects occur. In the case of $SO_2$ there exists considerable controversy concerning the actual chemical species involved in the several health effects associated with $SO_2$.

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[4] C.M. McKinney, E.P. Ferro, and W.J. Wenger, Analysis of Crude Oils from 546 Important Oilfields in the United States, Bureau of Mines Report No. 6819, 1966.

### 1.3.2 Freshwater Requirements

The need for large quantities of freshwater to produce steam in regions experiencing chronic water shortages may represent a serious constraint on the development of a steam injection project. If the cyclic steam soak method is under consideration, then it may be possible to adjust the water use periods to natural trends in water supply levels in order to alleviate competition for water during dry seasons. Problems associated with produced water disposal are addressed in Section IV.D.

## 2. In-Situ Combustion

### 2.1 Introduction

Although thermal recovery methods have become more widespread over the last several years, most of the current activity has been directed toward the use of steam injection methods. However, there are still several productive and successful fireflood projects underway. Recent pilot efforts have been directed at evaluating the wet combustion processes that are theoretically more economical than the straightforward dry combustion method. Both of these technologies are discussed below in terms of the resources they require and the environmental residuals they generate. Local air quality effects are potentially the most severe impacts to be expected. Water treatment and brine disposal effects are similar to those encountered with conventional technology.

Although this technology is considered by many petroleum engineers to be still in the developmental stage, there are quite a number of projects currently underway. Table IV-17 contains a list of known projects, showing considerable diversity in the size and location of the projects.

### 2.2 Process Description

In-situ combustion methods are based on generating heat within the oil reservoir by burning part of the oil present. A typical procedure involves pumping air into the

## TABLE IV-17

## CURRENT IN-SITU COMBUSTION PROJECTS IN THE UNITED STATES

| FIELD | STATE | COUNTY | OPERATOR | AREA, ACRES | NUMBER WELLS PROD. | NUMBER WELLS INJ. | DEPTH FT. | PROJECT* MATURITY | ENHANCED PROD. bo/d |
|---|---|---|---|---|---|---|---|---|---|
| Combustion Projects | | | | | | | | | |
| Kern River | Cal. | Kern | Chans. West | 5 | 4 | 1 | 400 | JS | 20 |
| Lost Hills | Cal. | Kern | Mobil | 140 | 50 | 5 | 300 | HF | 500 |
| Midway-Sunset | Cal. | Kern | Chans. West | 157 | 12 | 3 | 1,500 | JS | 300 |
| Midway-Sunset | Cal. | Kern | Mobil | 150 | 31 | 5 | 2,700 | 75% comp. | 507 |
| Midway-Sunset | Cal. | Kern | Mobil | 390 | 40 | 5 | 1,600 | 30% comp. | 293 |
| Paris Valley | Cal. | Monterey | Husky-ERDA | -- | 18 | 5 | 800 | JS | -- |
| Brea-Olinda | Cal. | Orange | Union | 44 | 20 | 2 | 3,500 | HF | 3-500 |
| Cat Canyon | Cal. | Santa Barbara | Conoco | 3 | 4 | 1 | 3,900 | JS | -- |
| Russel Ranch | Cal. | Santa Barbara | ARCO | 20 | 6 | 1 | 3,500 | NC | 0 |
| Robinson | Ill. | Crawford | Marathon | 130 | 41 | 3 | 1,000 | NC | 0 |
| Bellevue | La. | Bossier | Cities | 10 | 21 | 4 | 400 | NC | 300 |
| Bellevue | La. | Bossier | Cities | 10 | 21 | 4 | -- | JS | -- |
| Bellevue | La. | Bossier | Getty | 513 | 194 | 55 | 330 | HF | 2,000 |
| Pine Island | La. | Caddo | Conoco | 60 | 17 | 6 | 1,023 | HF | 50 |
| W. Heidelberg | Miss. | Jasper | Gulf | 300 | 6 | 1 | 11,750 | HF | 430 |
| W. Heidelberg | Miss. | Jasper | Gulf | 5 | 3 | 1 | 5,000 | JS | 100 |
| Red Bank | Ok. | Creek | Sun | 200 | 6 | 2 | 3,300 | NC | 100 |
| Loco | Ok. | Stephens | Conoco | 24 | 25 | 5 | 220 | JS | 30 |
| West 76 | Tex. | Duval | Mobil | 546 | 8 | 1 | 1,350 | NC | 90 |
| Talco | Tex. | Franklin&Titus | Exxon | 20 | 7 | 1 | 4,200 | Term. 10-75 | 30-40 |
| Gloriana | Tex. | Wilson | Sun | 513 | 9 | 2 | 1,600 | Term. 1-74 | -- |
| Glen Hummel | Tex. | Wilson | Sun | 600 | 18 | 4 | 2,300 | NC | -- |
| Little Tom | Tex. | Zavala | Hanover-ERDA | 14 | 3 | 1 | 2,700 | JS | 0 |

*HF = half finished; NC = nearing completion; JS = just started; Term. = terminated.

Source: "U.S. Thermal Recovery Activity Growing Steadily," Production Report, Oil and Gas Journal 74(14) (April 5, 1976), pp. 112-113.

formation through a former production well to feed an expanding burning zone which enhances oil production at surrounding wells.

This burning zone reaches temperatures of 600° F to 1,200° F depending upon the reservoir's physical characteristics and the operating conditions of the project. The heat from the burning front produces coke in the region ahead of the burning zone through the cracking and distillation of crude oil which dissociates the lighter from the heavier hydrocarbons. These coke residual fractions are composed of high boiling point hydrocarbons containing oxygen, sulfur, nitrogen, and trace metals, and form the materials which fuel the combustion process. Therefore, the ability of a crude to produce coke has a direct impact on the viability of a fireflood project.

Another important zone ahead of the burning front is made up of vaporized light hydrocarbons. As these gases are driven through the reservoir, they displace some of the oil, thereby improving the oil recovery at the nearby producing wells. As the combustion zone advances in the reservoir, oil, lighter hydrocarbons, water, and combustion gases are all driven toward the production wells. The burned out zone left behind is made up of hot, clean, fine-grained sand.

This heat contained in the combusted zone is of little value to the processes enhancing oil recovery beyond the flame front, and therefore represents a considerable loss of energy efficiency. Two methods have been developed to improve this situation, and the term wet combustion is generally applied to both.

The simplest wet combustion process involves shutting down air injection once the burning front has reached a predetermined size, and injecting water in its place. This water will transfer the bulk of the residual heat in the depleted zone across the burn front. Initially, the water is quickly transformed to a super-heated steam which penetrates the cool zone ahead of the burn front, thereby enhancing production in a steam drive mode well beyond the burn front. As the initial heat charge is spread across the front, continued waterflooding will resemble a hot water flood situation where the water serves as a pressure as well as thermal transfer medium, taking advantage of lower oil viscosity due to the increased temperatures present. Finally, if the waterflood is allowed to continue up to the limit of economic viability, the process becomes a straightforward waterflood.

The second wet combustion method is referred to by its patent name "COFCAW" (combination of forward combustion and waterflooding) and was developed by the Amoco Production Company (formerly Pan American Oil Company). This process employs a water injection strategy that allows intimate air and water injection. In this dynamic process the burn region is limited to an area termed the heat bank. The area behind the front no longer burns until the coke supply is consumed, since the heat has been mostly scavenged by the injected water. Some of the injected water then occupies this region and is continually fed toward the heat bank itself. As soon as it contacts the heated area it is converted to steam which flows on ahead of the bank, displacing much of the oil. This displacement also reduces the volume of coke which is eventually produced. While this is occurring, enough air is supplied to maintain the temperature of the heat bank against those losses due to phase changes and heat conduction to the surrounding formations. Since the heat bank is of limited extent, and its optimum temperature needs to be only somewhat greater than the vaporization point of water at reservoir pressures, the demands upon the air injection rate are reduced to about one-third of the levels required for dry combustion.

## 2.3 Environmental Impacts

The main substances required for the various combustion processes described above are air, water, and oil. The first of these is in abundant supply and needs no further consideration. Water injection is necessary in the wet combustion processes only, and is in many places a heavily utilized resource. The oil in place which is burned as the primary heating fuel is a non-renewable resource. Therefore, the major resource of concern in the fireflood process is the amount of water utilized.

### 2.3.1 Water Consumption

The Bellevue fields of Louisiana are currently under development by the two-stage wet combustion process of fireflooding followed by waterflooding. This area appears to be quite representative of the fields listed in Table IV-17 above. According to performance data from the project run by Cities Service Oil Company, the water-to-oil ratio in the period following the combustion stage was about 18 barrels of water per barrel of oil recovered.[5] As the formation cools down and the recovery becomes essentially a waterflood process, water consumption rates increase into the range of 30 to 40 barrels of water per barrel of oil recovered. In all, significant thermal enhancement proceeds for about a year after the fireflood, with the warm waterflood continuing for another 1 to 2 years. Water use rates for the COFCAW-type process are theoretically much lower, around 5 to 6 barrels of water per barrel of oil recovered, but this rate spans the combustion period instead of the waterflood stage.

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[5] T.P. Little, "Fireflooding at Bellevue," Petroleum Engineer 47(12) (November 1975).

### 2.3.2 Atmospheric Emissions and Effects

The atmospheric emissions associated with in-situ combustion arise from activities at both the injection and production wells. Table IV-18 presents the composition of important quantities in the process gas stream as averaged over 31 combustion projects. Regional variations in reservoir characteristics and operating characteristics of combustion projects would affect the level of emissions produced. The assumption of negligible $SO_2$ emissions is based on the observed pH of the produced water from the projects surveyed.

Carbon monoxide and low molecular weight hydrocarbons are the chief components that might affect the air quality. In order to interpret the figures derived for the number of tons of pollutant per barrel of oil produced, it is necessary to consider the amount of these releases at an average producing well. Using production figures contained in Table IV-17, all but one of the successful projects had production averages between 10 and 25 barrels of oil per day per well. The one that did not conform was the West Heidelberg project in Jasper County, Mississippi, whose other characteristics also tend to isolate it (note particularly its depth). This project is producing 71 barrels of oil per day per well. Therefore, it is assumed that an average well produces 16 barrels of oil per day. Statements about the 71 bbl/day representing a worst case for wellhead pollutant releases are risky since that particular project might possess exceedingly atypical air-to-oil recovered ratios as well.

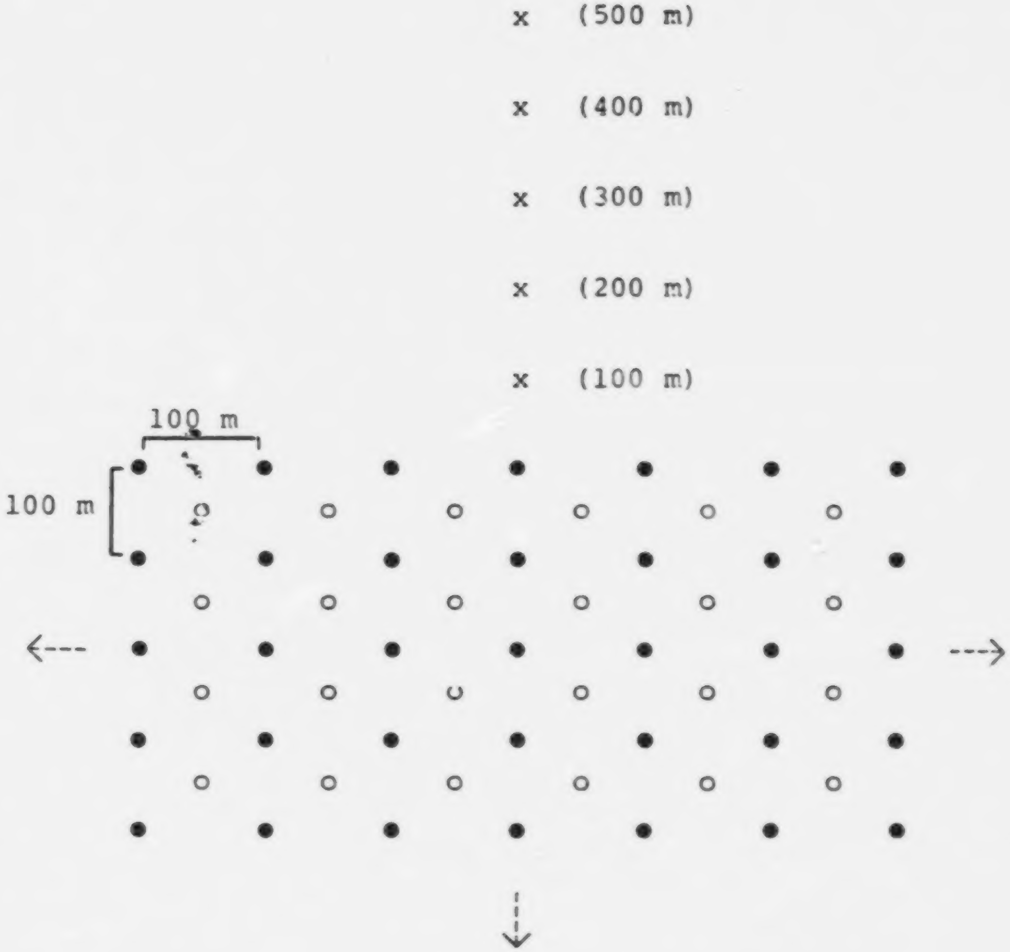
For the purposes of estimating the highest possible downstream concentration of a pollutant released at a production well of an in-situ combustion project, it is assumed that an entire field is developed by inverted five-spot injection projects of 2.5 acres each. This results in a grid of ground level point sources set 100 meters apart. It is assumed that the field boundary is at least 100 meters away from the closest well (see Figure IV-4).

## TABLE IV-18

## AVERAGE POLLUTANT LOAD IN PROCESS GAS STREAM FROM IN-SITU COMBUSTION PROJECTS

| POLLUTANT | EMISSION RATE |
|---|---|
| $SO_2$ | Emitted in late phases only, no data |
| CO | $6.25 \times 10^{-3}$ ton/bbl |
| Hydrocarbon (non-methane) | $1.27 \times 10^{-3}$ ton/bbl |
| $NO_x$ | Formation not favored due to combustion temperatures -- nitrogen gas favored |

Source: Energy Resources, Potential Environmental Consequences of Tertiary Oil Recovery, 1976, p. 52.



x (500 m)
x (400 m)
x (300 m)
x (200 m)
x (100 m)
100 m
100 m

Figure IV-4. A representation of a large-scale fireflood project. "x" represents measurement points, "●" represents production wells, and "o" represents injection wells.

The pollutants of primary concern in in-situ combustion, carbon monoxide and hydrocarbons, have short-term air quality standards, unlike those emitted by steam boiler emission. The standard for hydrocarbons is expressed as a 3-hour average, and the two for carbon monoxide as 1-hour and 8-hour averages. For this reason, the method for estimating the worst-case situation differs from that employed in estimating the longer term averages associated with $SO_2$, $NO_x$, and PM emissions from steam injection projects. The procedure follows the standardized method developed by the EPA and described in the widely used and accepted Workbook of Atmospheric Dispersion Estimates.[6]

The method develops estimates of a normalized factor, $\chi u/Q$, from which the ground level concentration ($\chi$) can be calculated for a given wind speed (u) and emission rate (Q). Table IV-19 shows the resulting values for atmospheric stability classes A (unstable), D (neutral), and F (stable). Clearly, class F represents the worst case, and it will be the focus of all further analysis. The values correspond to the locations of receptors, set at increments of 100 meters, along one of the source grid lines, as shown by the x's in Figure IV-4.

TABLE IV-19

VALUES OF $\chi u/Q^1$ FOR SOURCE ARRAY SHOWN IN FIGURE IV-3

| DISTANCE (m) | STABILITY CLASS | | |
|---|---|---|---|
| | A | D | F |
| 100 | .00149 | .0143 | .0573 |
| 200 | .00064 | .0063 | .0253 |
| 300 | .00036 | .0039 | .0153 |
| 400 | --- | .0027 | .0103 |
| 500 | --- | .0020 | .0073 |

[1] $\chi$ = pollutant concentration ($g/m^3$)
u = wind speed (m/sec)
Q = emission rate (g/sec)

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[6] D.B. Turner, Workbook of Atmospheric Dispersion Estimates, for the U.S. Environmental Protection Agency, 1970, pp. 11-17.

A 16 bbl/day well produces about 200 pounds of carbon monoxide per day, or about 1 g/sec. If this is released continuously to the atmosphere from every production well in the described field under the worst case conditions of (1) release height at ground level, (2) wind speed of 1 meter per second, and (3) stability class F (very stable), then the resultant downwind concentration are those listed in Table IV-20. These estimates are appropriate for averaging times of 1 hour. The Federal standard for ambient carbon monoxide concentrations is 40 $mg/m^3$ with an averaging time of 1 hour. The results indicate no violations of the 1-hour standard are expected even under worst case meteorological conditions.

TABLE IV-20

WORST CASE ESTIMATE OF DOWNWIND CO CONCENTRATIONS FROM A LARGE FIELD UNDERGOING FIREFLOODING

| DISTANCE (m) | CONCENTRATION ($mg/m^3$) |
|---|---|
| 100 | 34.9 |
| 200 | 15.4 |
| 300 | 9.3 |
| 400 | 6.3 |
| 500 | 4.5 |

A similar analysis for the produced non-methane hydrocarbons shows that an average well may release up to 40.6 pounds per day, or 0.2 g/sec. If this is vented without control under the same conditions outlined above, then the maximum worst case concentrations are those listed in Table IV-21. In this case, these values represent 3-hour averages. The national standard for non-methane hydrocarbons is 160 $\mu g/m^3$, where the averaging time is 3 hours. These results show the possibility of significant violations of the national hydrocarbon standard under the worst-case assumptions used for this analysis.

## TABLE IV-21

## WORST CASE ESTIMATE OF DOWNWIND NON-METHANE HYDROCARBON CONCENTRATION FROM A LARGE FIELD UNDERGOING FIREFLOODING

| DISTANCE (m) | CONCENTRATION ($\mu g/m^3$) |
|---|---|
| 100 | 5,800 |
| 200 | 2,500 |
| 300 | 1,500 |
| 400 | 1,000 |
| 500 | 730 |

In order to control the potential problems associated with hydrocarbon release and stay within the standards, some precautions can be taken. In certain regions of the country, such as Texas, secondary combustion or flaring may be required if the release rate is sufficiently high. This is not expected to preclude the operation of in-situ combustion projects. In fact, large projects may find it economical to recovery these gases for sale. The major areas of concern would be those suffering from oxidant problems. The presence of a project near these areas may aggravate the problem through fugitive hydrocarbon emissions alone.

Emissions at an in-situ project may also arise as a result of the compressors needed to inject air into the reservoir. The units range between 100 and 1,200 horsepower and run on either natural gas or electricity. The electric models are used where disposable quantities of gas are limited, and they represent a minute power drain on the utility. Therefore, their impact on air quality is insignificant.

Models that run on natural gas are typically rated at 1,000 hp. The pollutants of concern for these units are the oxides of nitrogen. A recent analysis of a large complex of 40 of these 1,000 hp compressors has shown that a group as large as this tends to produce ambient $NO_2$ levels of more than twice the annual standard of 100 $\mu g/m^3$ in Texas.[7]

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[7] Personal communication, Texas Air Control Board, Austin, Texas, 1972.

Therefore, it is assumed that isolated single units typical of those used at fireflood injection wells will produce little long term impact. Further discussion about compressor engine impacts is presented in Section IV.E.

The environmental risks uniquely associated with fireflood technologies relate to the emittants from the gas stream, particularly hydrocarbons and carbon monoxide. While the impacts of airborne pollutants vary from site to site depending on the rate and extent of dispersion, certain generalizations can be made about the risks attached to these substances based on their general toxic effects, as discussed in Appendix K.

### 2.3.3 Water Effluents

Water residuals from the fireflood process include such potential contaminants as trace metals and metal oxides from the crude which might be dissolved in the acidic waters. Table IV-22 presents a list of trace elements found in crude oils from several distinct oil regions. These may represent a contamination problem through spills and leaks of low pH water.

TABLE IV-22

TRACE ELEMENTS IN U.S. CRUDE OIL

(parts per million)

| | ORIGIN OF CRUDE | | |
|---|---|---|---|
| ELEMENT | CALIFORNIA | LOUISIANA | TEXAS |
| Antimony | < 0.007 | 0.05 | < 0.01 |
| Arsenic | < 0.007 | 0.05 | < 0.12 |
| Barium | < 0.06 | 0.09 | < 0.14 |
| Manganese | 0.018 | 0.027 | < 0.05 |
| Nickel | 77.0 | 4.4 | 3.3 |
| Tin | < 0.6 | 0.5 | < 1.0 |
| Vanadium | 48.0 | 1.0 | 1.9 |

Source: Energy Resources Company Inc., Potential Environmental Consequences of Tertiary Oil Recovery, July 1976, p. 53.

The use of water in the wet combustion stage of the fireflood process will necessarily preclude this recovery mode from operating in areas experiencing chronic water shortage problems. Problems associated with the highly corrosive brine are discussed and evaluated in Section IV.D.

### 3. Miscible Recovery Processes

### 3.1 Introduction

One method of increasing oil production from a reservoir is to employ a process that counteracts the forces which cause the retention of oil in a reservoir matrix. Once these forces are overcome a fluid can be swept through the reservoir recovering the remaining oil. Solvents which can dissolve oil and are often employed include alcohols, ketones, refined hydrocarbons, condensed petroleum gases, carbon dioxides, liquefied natural gas or even various flue gases.[8] Of these, carbon dioxide will probably be the most widely used. As the solvent becomes enriched with oil, its miscibility with any remaining oil decreases. This places a limitation on the amount of oil that can be recovered. There are three basic miscible displacement processes: high pressure gas, enriched gas, and miscible slug.

The factors that affect miscibility include reservoir length, injection rate, porosity, permeability of the reservoir matrix, size of reservoir, temperature, and pressure.[9]

### 3.2 Carbon Dioxide Methods

There are essentially three types of carbon dioxide injection presently in use:

- Injection of carbon dioxide followed by water or carbonated water (carbon dioxide and water).
- Direct injection of carbonated water.
- Injection of carbon dioxide alone at high pressures.

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[8] Interstate Oil Compact Commission, Secondary and Tertiary Oil Recovery Processes, Oklahoma City, Oklahoma, 1974.

[9] Interstate Oil Compact Commission, Secondary and Tertiary Oil Recovery Processes, 1974.

The method chosen depends on the miscibility of the oil with the particular form of carbon dioxide being injected. This in turn depends greatly on the reservoir temperature and pressure. For purposes of assessing the environmental impacts a process utilizing both carbon dioxide and water will be considered since this process is the one with the most serious environmental impact.

The decision to use carbon dioxide at all depends to a large extent on the availability of a nearby inexpensive source of carbon dioxide such as a natural gas processing plant, ammonia plant, or gas field. There are three possible ways to bring carbon dioxide to the oil field: truck, railroad tank car, and pipeline.

Carbon dioxide is presently employed on only one project producing over 1,000 barrels of oil per day (Sacroc produces 35,000 barrels per day). It is being used on 11 projects in total (Table IV-23). Two projects (one partly funded by ERDA, the other by Pennzoil) are scheduled to start up shortly in West Virginia. Phillips is planning a project for Utah in 1978.

The environmental impacts associated with carbon dioxide/miscible methods can be classified in two major categories:

1. Transportation of the carbon dioxide to the site and development of facilities to supply water if it is to be used along with carbon dioxide.

2. Environmental problems such as air emissions from production equipment and the possibility of surface or groundwater contamination during production or brine disposal operations.

## 3.3 Environmental Impacts

### 3.3.1 General

Shell Oil Co.[10] is using carbon dioxide at its Little Creek Field in Lincoln and Pike Counties, Mississippi, in an attempt to recover 55 million barrels of oil left after waterflooding. Injection of carbon dioxide is at a rate of 230 tons per day and the carbon dioxide is delivered to the distribution system in tank trucks and 150-ton railroad tank cars. In order to maintain the present rate of feed, over 10 tank cars have to be moved to the site each week. If a field had no railroad siding and the carbon dioxide were

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[10] Oil and Gas Journal (September 2, 1974).

# TABLE IV-23

## $CO_2$ MISCIBLE PROJECTS IN THE UNITED STATES

| FIELD | STATE | COUNTY | OPERATOR | AREA, ACRES | NUMBER WELLS PROD. | NUMBER WELLS INJ. | DEPTH FT. | PROJECT MATURITY | ENHANCED PROD. BO/D |
|---|---|---|---|---|---|---|---|---|---|
| Dugout Creek | Wyo. | Johnson | Texaco | -- | 3 | 2 | 2,000 | NC | -- |
| Lick Creek | Ark. | Bradley-Union | Phillips | 1,640 | 32 | 14 | 2,500 | JS | -- |
| McCallum Unit | Colo. | Jackson | Conoco | 601 | 19 | 4 | 1,250 | HF | -- |
| Little Creek | Miss. | Pike | Shell | 40 | 3 | 1 | 10,800 | NC | 133 |
| Ciosset | Tx. | Crane & Upton | Shell | 1,700 | 17 | 9 | 5,300 | JS | 1,100 |
| N. Cowden | Tx. | Ector | Amoco | 12 | 2 | 6 | 4,300 | -- | -- |
| S. Gillock | Tx. | Galveston | Amoco | 5,700 | 38 | 11 | 9,000 | HF | -- |
| Slaughter | Tx. | Hockley | Amoco | 12 | 2 | 6 | 4,950 | -- | -- |
| Two Freds | Tx. | Loving, Reeves, Ward | HNG | -- | 17 | 11 | 4,900 | JS | -- |
| Kelly-Snyder | Tx. | Scurry | Socal | 50,000 | -- | -- | 6,900 | 35% compl. | 35,000 |
| Wasson | Tx. | Yoakum | Arco | 320 | -- | 9 | 5,100 | Susp. 2-75 | -- |

NC = nearing

JS = just started

HF = half finished

Compl. = completed

Susp. = suspended

Source: The Oil and Gas Journal, April 5, 1976, pp. 120-121.

delivered by 20-ton trucks, the number of deliveries would increase by a factor of nearly eight. The Shell project is a pilot study, so full development of the field might necessitate delivery of carbon dioxide by pipeline from the source.

In Scurry County, Texas, the Sacroc Unit[11] is using carbon dioxide followed by water injection. The carbon dioxide is being delivered by pipelines from a gas field 200 miles away. The environmental impacts associated with this method include those involved in the construction of the pipelines and the air, water, noise, and traffic problems associated with any such construction project and the running of pipelines along rights of way which may impact the ecology and land in particular areas. The alternative delivery method of carbon dioxide to the Sacroc Unit implies over 600 truck deliveries per day and a total of over 240,000 miles of truck travel per day. Almost certainly a carbon dioxide injection project of any size will require a pipeline delivery system.

### 3.3.2 Water Requirements

The carbon dioxide project at Sacroc consumes large quantities of water. At the present time, over 500,000 barrels per day are being used[12] while 35,000 barrels of oil are being produced from $CO_2$ injection. About 40 percent of the water used is makeup; the rest is recirculated. Part of Sacroc's makeup supply comes from a nearby lake and the rest from saltwater wells. The water supply, treatment and distribution systems at Sacroc were already in place. Usually this would be the case, although it is possible that someone planning to use tertiary recovery might demand higher quality water than used in a waterflooding operation.

The water used at Sacroc has to be treated for various reasons. Ferric sulfate and lime are necessary to remove solids from the water and to prevent plugging of the pores in the oil formation and to adjust the pH. Chlorine is added to destroy bacteria which can cause slime buildup in the formation and also to cut down on corrosion of the steel pipe used for casing. Oxygen is also desorbed by methane stripping to reduce the corrosiveness of the water.

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[11] Oil and Gas Journal (April 10, 1972).

[12] Personal communication, Mr. Robert Schooler, Chevron Oil Co., during week of August 16, 1976.

At the Sacroc facility, approximately 175 pounds of ferric sulphate, 450 pounds of lime and 50 pounds of chlorine are used per million gallons of water treated.[13] At the present time, over 7 million gallons are being treated on a daily basis.

### 3.3.3 Atmospheric Emissions

The operating conditions at Sacroc require over 80,000 horsepower of compression capacity to maintain pressure and deliver required quantities of carbon dioxide. The power required for any carbon dioxide injection project comes from an electrical source or from the use of diesel fuel or natural gas. The impacts on air quality will be either at the power plant, where the electricity is generated, or on-site, where the diesel- or natural gas-fired compressors are operating. At Sacroc, power is generated using natural gas at six booster stations. Due to the high temperatures reached, nitrous oxide emissions will occur. The impacts of these emissions from small engines are treated in Section IV.E. However, a recent analysis of a complex of 40 1,000-hp compressors at a booster station in Texas indicated a level of nitrogen dioxide more than twice the existing annual standard.[14]

Carbon dioxide also speeds the reaction of hydrogen sulfide and moisture with metal causing hydrogen embrittlement. Hydrogen sulfide, which is then released, can be a potentially lethal gas at concentrations that dull a person's sense of smell, making it difficult to detect the characteristic "rotten egg" odor. Special precautions are necessary to insure that the proper metals are used in any component that might fail and result in hydrogen sulfide emissions. In February of 1975 an accident at an experimental carbon dioxide injection well resulted in the deaths of nine people.[15]

Additional environmental impact during activity at a carbon dioxide project could arise from the emissions from equipment at the production site from storage tanks, vapor recovery units and heater treaters.

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[13] Personal communication, Mr. Cecil Jordan, Sacroc Project, during week of August 23, 1976.

[14] Personal communication, Texas Air Control Board.

[15] "Insidious Killer - A Lethal Gas Freed in Oil-Gas Production Poses a Rising Hazard," Wall Street Journal (December 5, 1975).

### 3.3.4 Water Pollution

Other potential environmental impacts that are common to all carbon dioxide projects include brine disposal, groundwater contamination resulting from a cracked casing during production and emissions from equipment at the production site.

Excess brine is normally stored in impervious pits prior to disposal. If these pits leak or fail, they could potentially impact either nearby surface water or ground water. Brine disposal can cause groundwater contamination if the well leaks into a freshwater aquifer.

### Other Gas/Miscible Methods

In addition to the carbon dioxide miscible method of enhanced recovery mentioned in Section IV.C.3.1, other miscible methods include the use of hydrocarbon or other miscible gases (see Table IV-24).

Atlantic Richfield Oil Company is currently producing 54 million cubic feet per day of flue gas which is 87 percent nitrogen, 12 percent carbon dioxide, and 1 percent carbon monoxide by volume at their Block 31 field in Crane County, Texas. The flue gas is then injected into the formation at 3,500 psi to maintain miscibility pressure. A plant was built which uses residue gas produced as the fuel to produce the flue gas. Nine cubic feet of flue gas are produced per cubic foot of gas burned. The capital cost of the plant was justified by the savings from discontinued purchase of makeup natural gas plus sales of excess produced gas. At the present time, the field is producing approximately 16,000 barrels of oil per day.

The decision to use a particular miscible recovery process depends on the amount of oil that can be recovered and the costs and availability of the various gases involved. It also depends on the particular field characteristics such as what pressures can be maintained. These variables in turn impact the environment to different degrees.

If carbon dioxide is used, construction of a pipeline is likely to be necessary. However, if a flue gas is used, it

## TABLE IV-24

## OTHER MISCIBLE PROJECTS IN THE UNITED STATES

| FIELD | STATE | COUNTY | OPERATOR | AREA ACRES | NUMBER WELLS PROD. | INJ. | DEPTH FT | PROJECT MATURITY | ENHANCED PROD. BO/D |
|---|---|---|---|---|---|---|---|---|---|
| Greeley | Cal. | Kern | Mobil | 550 | 8 | 1 | 10,600 | Term. 10-75 | 600 |
| Midway-Sunset | Cal. | Kern | Socal | 530 | - | - | 5,200 | Term. 1974 | - |
| Ventura | Cal. | Ventura | Shell | 325 | 18 | 15 | 10,000 | HF | 800 |
| Black Bayou | La. | Cameron | Shell | 6.2 | 2 | 1 | 4,800 | NC | 180 |
| Black Bayou | La. | Cameron | Shell | 8.8 | 3 | 1 | 4,710 | NC | 65 |
| Black Bayou | La. | Cameron | Shell | 16.7 | 1 | 1 | 5,700 | NC | 100 |
| Weeks Island | La. | Iberia | Shell | 679 | 10 | 2 | 14,000 | JS | - |
| Block 31 | Tx. | Crane | ARCO | 7,840 | 86 | 27 | 8,500 | 74% Compl. | 16,000 |
| Levelland | Tx. | Hockley | Amoco | 1,200 | 40 | 28 | 4,800 | JS | - |
| Levelland | Tx. | Hockley | Amoco | 13 | 2 | 6 | 4,800 | - | - |
| Slaughter | Tx. | Hockley | Amoco | 12 | 2 | 6 | 4,950 | - | - |
| Bridger Lake | Utah/Wyo. | Summit/Uinta | Phillips | 3,800 | 7 | 1 | 15,600 | 25% Compl. | 1,000 |
| Charlson | N. Dak. | McKenzie | Texaco | 9,100 | 24 | 7 | 8,500 | HF | - |
| E. Velma | Ok. | Carter-Stephens | Amoco | 50 | 17 | 3 | 5,500 | HF | 300 |
| Fairway | Tx. | Anderson & Henderson | Hunt | 22,618 | 118 | 47 | 9,900 | HF | 28,500 |
| Winkleman Dome | Wyo. | Fremont | Amoco | 752 | 39 | 13 | 3,300 | HF | - |

Term. - terminated
HF - half finished
NC = nearing
Comp. = Completed

Source: Oil and Gas Journal (April 5, 1976): 126.

is possible to avoid a pipeline and, therefore, confine the environmental impact to the locale of the field since a plant can be built on site. However, some of the valuable produced gas has to be consumed to produce flue gas. With time, the gas produced becomes contaminated with flue gas and a cryogenic plant might be necessary to strip the nitrogen. If hydrocarbon gas is used, it might be necessary to build a pipeline to supply makeup gas.

Corrosion problems with flue gas can be serious if nitrogen oxides or sulfur are present.[16] However, problems with the generation and handling of flue gas should diminish as expertise is built up at projects such as Block 31. There are potential environmental advantages to using flue gas since the injection of flue gas from an existing system provides a natural disposal system to reduce atmospheric pollution.[17]

Other potential environmental impacts from projects utilizing flue gas or hydrocarbon gas are not unique to the process. Brine disposal and emissions from compressors necessary to inject the flue gas are discussed in Sections IV.D and IV.E. Larger compressors are needed than for conventional natural gas injection since higher pressures are necessary to maintain the miscibility of flue gas with oil.

The use of flue gas as a means of enhanced recovery will probably be considered in the future on a field by field basis as projects utilizing produced gas or enriched gas find it more economical to invest in the capital facilities to generate the flue gas and save on hydrocarbon usage. During the last two years, only one hydrocarbon miscible project, the Charleson Field in North Dakota, has been started, while another project, the Midway-Sunset Project, has been terminated because liquefied petroleum gas became too valuable to inject.[18]

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[16] Little, "Fireflooding at Bellevue," 1975; Interstate Oil Compact Commission, Secondary and Tertiary Oil Recovery Processes.

[17] Interstate Oil Compact Commission, Secondary and Tertiary Oil Recovery Processes.

[18] Oil and Gas Journal (April 5, 1976).

## 4. Surfactant/Polymer

### 4.1 Introduction

In secondary oil production operations, water is injected into an oil-bearing formation, and the oil is driven by the water stream toward the production well. Initially, the movement of oil is caused by the water pushing it through the formation. Following water breakthrough, however, the oil must be produced by being mechanically entrained in the water drive. Since oil and water are immiscible, however, the water will tend to bypass oil which is trapped and held by capillary forces within the interstices of the formation.

These problems can be partially overcome by the use of a surfactant together with water injection. In the so-called micellar flood technique, a "slug" containing a high concentration of surfactant is injected into the reservoir. The surfactant molecules form an interface layer between the oil and water, stabilizing oil/water emulsions, and, in effect, making the oil miscible with the water. Since the water/surfactant solution is miscible with the oil, it can displace the oil in the formation and move it more effectively to the production well. Furthermore, by reducing the interfacial tension between oil and water, the surfactant acts to reduce the capillary forces acting to hold the oil within the reservoir. This too enhances oil recovery rates. Surfactants are not used alone in micellar slugs, but are frequently combined with cosurfactants such as alcohol and salts, in order to control the stability and viscosity of the fluid.

As discussed in Section IV.D, well failure can result in the leakage of injected or produced fluids into aquifers used as sources of groundwater supplies. In the case of tertiary surfactant techniques, the leaked fluids would contain not only the trace metals and hydrocarbons characteristic of standard produced waters, but also significant levels of surfactants and cosurfactants. Many of the surfactants or cosurfactants used are toxic chemicals with known potential for impact on beneficial groundwater uses, including livestock watering, irrigation, and human consumption. Existing water quality criteria for surfactants and particular cosurfactants may be a few orders of magnitude lower than the concentrations actually known to be found in produced fluids. Therefore, the possibility of the leakage of surfactant and cosurfactant containing produced fluids into ground-water formations is a cause for concern. The analysis of this problem is complicated by the fact that surfactants and cosurfactants may undergo a number of processes, such as adsorption and degradation, which may ameliorate their ultimate impact on groundwater supplies.

## 4.2 Process Description

The micellar-polymer flooding process is described in summary in Figure IV-5. The process consists of the following stages:

1. Preflush which is injected into the reservoir to adjust the salinity of the formation to be compatible with the optimum operating conditions of the surfactant. Bactericides may also be added to the preflush to prevent the growth of slime-producing organisms in production and injection wells.

2. Micellar Slug containing a high concentration of surfactant together with a cosurfactant, hydrocarbons, and electrolytes is injected.

3. Mobility Control Solution. One of the important operational problems related to micellar-polymer flooding is that of mobility control. If the mobility of the injected fluid is significantly greater than that of the reservoir oil, flow channeling (fingering) will develop, causing a significant portion of the oil to be bypassed. This problem is even greater in micellar operations than in conventional waterflooding, since the large difference between the slug and oil mobilities can result in a rapid dispersion of the micellar slug, thus reducing its effectiveness in displacing oil. In order to ameliorate this problem, polymeric "mobility buffers" are generally injected in order to control the movement of the micellar slug. The purpose of these buffers is to uniformly push the micellar slug through the formation.

4. Water Drive. This is the flow of water which pushes the micellar slug and the mobility buffer through the reservoir, up towards the production well.

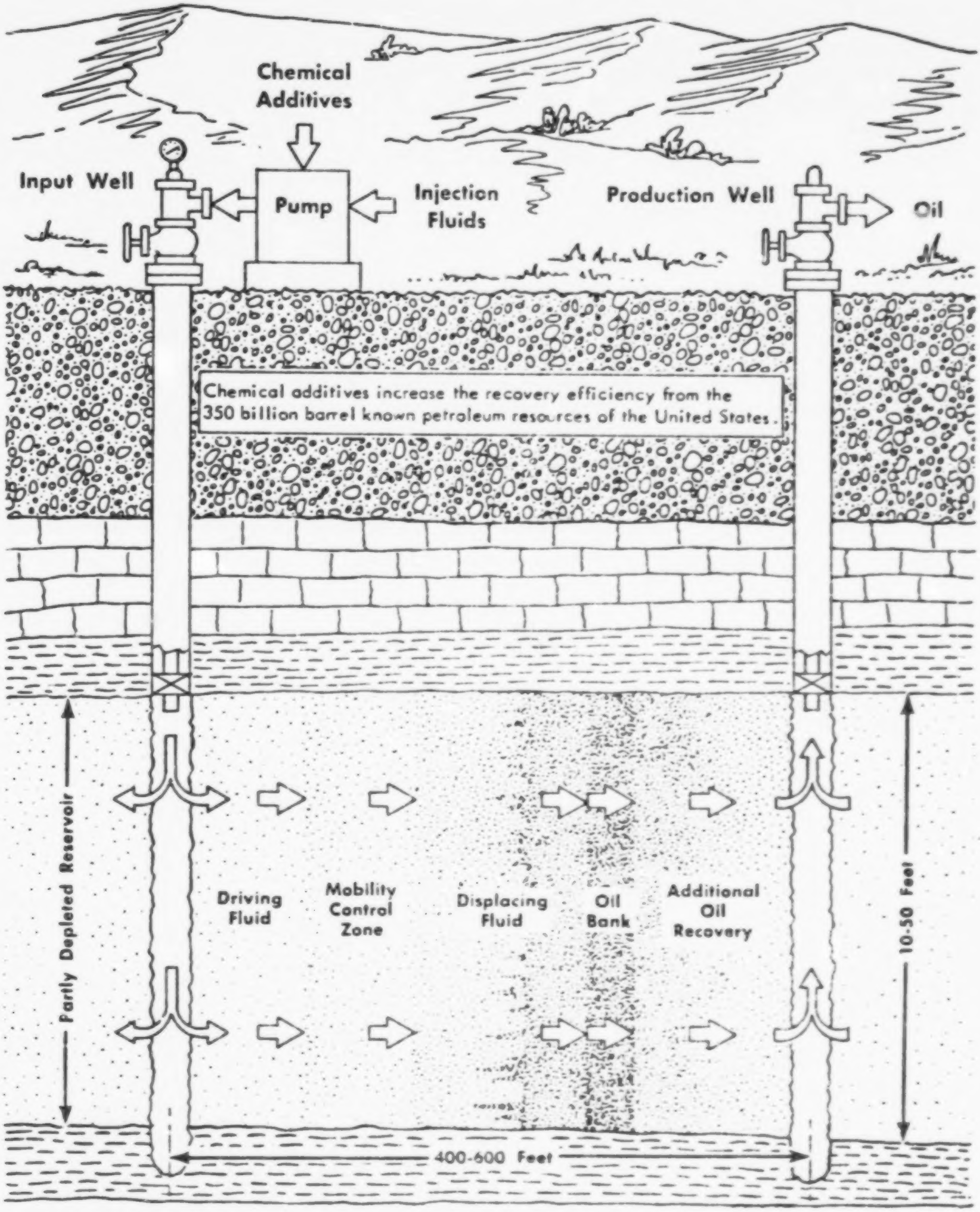
Chemical Additives
Input Well
Pump
Injection Fluids
Production Well
Oil
Chemical additives increase the recovery efficiency from the 350 billion barrel known petroleum resources of the United States.
Partly Depleted Reservoir
Driving Fluid
Mobility Control Zone
Displacing Fluid
Oil Bank
Additional Oil Recovery
10-50 Feet
400-600 Feet

Figure IV-5. The micellar-polymer flooding process. (Energy Research and Development Administration, *Enhancement of Recovery Oil and Gas*, Progress Review No. 1, January 1975, p. 11.)

## 4.3 Environmental Impacts

In micellar-polymer flooding a number of chemicals, used as surfactants, cosurfactants, and mobility buffers, are added to the waterflood. Appendix L contains lists of some of the chemicals which have been proposed for use in these applications in U.S. patents and in the technical literature. Injection of the flood is accomplished in the same way as conventional waterflooding with corresponding air emissions from the compressor (see Section IV.E). The primary impact of this technique remains the threat of chemical release.

If in the recovery process chemicals escape to the environment in sufficient quantities, their presence can degrade water supply quality and prevent beneficial use of ground and surface waters for such purposes as livestock water, irrigation, and use in a public water supply system. The release of the chemicals can occur from the reservoir (during the recovery process), or from the injection or production wells (in case of well failure). The nature of the risks associated with the presence of these chemicals in groundwater supplies is discussed in Section IV.D.

### 4.3.1 Water Requirements

Extensive data on water consumption by the micellar-polymer process are available as a result of previous operating experience at oil fields using this recovery method. [The figures cited in this section are taken from a report prepared by Energy Resources Co. Inc. on *Potential Environmental Consequences of Tertiary Oil Recovery* (Final Report, July 1976)]. Preflushing uses 1 to 6 barrels of high quality water per barrel of oil eventually recovered (the water must contain very low concentrations of divalent cations since these interfere with the action of the surfactant). From 0.1 to as much as 2 barrels of water are used per barrel of oil recovered in making up the micellar slug. The mobility buffer uses approximately 2 to 5 barrels of water per barrel of oil recovered. An additional 3 or more barrels of water per barrel of oil produced are then required to complete the flood. It is estimated, then, that a micellar-polymer flooding project which requires a preflush could require as much as 19 barrels of water per barrel of oil produced, of which up to 14 barrels must be of acceptably high quality.

### 4.3.2 Chemical Consumption

Chemical consumption by the micellar-polymer process includes approximately 5 to 15 pounds of surfactant per barrel of oil produced, 2 to 10 pounds of cosurfactant per barrel of oil produced, and 1 pound of polymer per barrel of oil produced (for use in the mobility buffer).

Approximately 25 percent of the fluids injected in a micellar-polymer operation will be irretrievably lost due to entrapment in the porous rock of the oil-bearing formation. Further loss of the surfactant will occur due to adsorption. Trushenski reported adsorption data ranging from 0.5 to 2 pounds per barrel of pore volume in a preflushed Berea sandstone, and between 1 to 3 pounds of surfactant per barrel of pore volume in a stone which was not preflushed.[19] Thus, a reasonable estimate of surfactant adsorption is 2 pounds of surfactant per barrel of pore volume, although of course the exact figure would differ widely depending on the nature of the formation, the chemistry of the surfactant, and the type and quantity of cosurfactant used. Assuming 50 percent saturation of pore volume with oil in a producing formation, then 2 pounds of surfactant are adsorbed per half barrel of oil produced, or 4 pounds per barrel of oil produced.

### 4.3.3 Water Pollution Effects

Surfactants used in micellar-polymer operations are soluble (to different extents) in both oil and water, so that some surfactant will be found both in produced water and in produced oil. The extent to which a surfactant will divide itself between oil and water fractions depends on its relative solubility in water and hydrocarbons, and is expressed in terms of a "partition coefficient" for that surfactant.

The partition coefficient can be used to calculate the fraction of total produced surfactant which will be found in the oil and water fractions:

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[19] S.P. Trushenski, Society of Petroleum Engineers Paper 4582, presented at the 48th SPE meeting, Las Vegas, Nevada, 1973.

$$W_{oil} = W(PR/(1+PR))$$

$$W_{water} = W(1/(1+PR)),$$

where W is the total weight of surfactant produced and $W_{oil}$ and $W_{water}$ are, respectively, the total weights of surfactant present in produced oil and produced water. P is the partition coefficient for the surfactant and R is the oil-to-water ratio of the produced fluids on a weight/weight basis. The total weights of surfactants in produced fluids can then be divided by the volume of the produced fluids to obtain an estimate of the concentration of surfactant in these fluids. The calculations shown in Table IV-25 are very rough. Actual values vary significantly from site to site. Still the estimated concentration of surfactant in the produced waters, 7,660 ppm, is approximately 15,000 times the EPA water quality criterion for surfactants in drinking water. Therefore, in this example if produced fluids escape into an aquifer due to well failure, a dilution of 15,000 times would be needed to reduce surfactant concentrations to a level which would not interfere with the beneficial use of ground water extracted from that aquifer. The dilution necessary to reduce the concentration of the cosurfactant to a "safe" level depends upon the particular cosurfactant used. Alcohols generally are used, but occasionally more toxic chemicals such as phenols may be used as cosurfactants (see Table L-6; cresol is a phenol derivative). If phenols are transported to water supplies, they can create undesirable tastes and odors, as well as significant toxicity problems, when they are chlorinated in drinking water disinfection plants. Maximum levels of 1 ug/l (.001 ppm) are recommended for phenols in waters used as the source of a public water supply. This represents a dilution of nearly 8 million-fold from the concentration calculated in Table IV-25 to be present in produced waters.

Fourteen field tests of micellar-polymer are currently in operation; these are listed in Table IV-26. In addition, 11 new projects are in the planning stages; these are shown in Figure IV-6.

As discussed in Section IV.D, the key problem involved in assessing the environmental risks of fluid injection is the possibility of well failure followed by leakage of injected or produced fluids into aquifers used as a source of a groundwater supply system. Ground water is used

## TABLE IV-25

## SAMPLE CALCULATION OF APPROXIMATE CONCENTRATIONS OF SURFACTANTS AND COSURFACTANTS IN PRODUCED FLUIDS

| | SURFACTANT | COSURFACTANT |
|---|---|---|
| Injected quantities; lb/bbl of produced oil | 15.00 | 10.00 |
| Lost due to entrapment in producing formations (assumed to be 25 percent) | 3.75 | 2.50 |
| Lost due to adsorption (4 lb surfactant/bbl oil produced) | 4.00 | -- |
| NET PRODUCED | 7.25 | 7.50 |
| Weights found in produced fluids ($P_{surf} = 0.7$; $P_{cosurf} = 0.5$; oil/water ratio = 0.5) | | |
| Oil Phase | 1.88 | 1.50 |
| Water Phase | 5.37 | 6.00 |
| Concentration in Produced Fluids (ppm) | | |
| Oil | 5,360 | 4,280 |
| Water | 7,660 | 8,550 |

Concentrations of final calculations are made (e.g., for the case of concentrations in produced oil) by dividing the weight of the chemical by the volume of oil produced (e.g., 1.88 lb surfactant/bbl of oil) and then using the appropriate conversion factors to change this into mg/l (parts per million, ppm).

Source: Energy Resources, Tertiary Oil Recovery, 1976. p. 36.

## TABLE IV-26

## SURFACTANT RECOVERY PROJECTS IN THE UNITED STATES

| FIELD | STATE | COUNTY | OPERATOR | AREA, ACRES | NUMBER WELLS PROD. | INJ. | DEPTH FT. | PROJECT MATURITY | ENHANCED PROD. BO/D |
|---|---|---|---|---|---|---|---|---|---|
| Robinson | Ill. | Crawford | Marathon | 40 | 27 | 18 | 1,000 | NC | -- |
| Robinson | Ill. | Crawford | Marathon | 116 | 55 | 39 | 1,000 | JS | -- |
| Benton | Ill. | Crawford | Shell | 160 | 12 | 6 | 2,100 | HF | 40 |
| Salem | Ill. | Crawford | Texaco | 5 | 1 | 4 | 1,800 | NC | -- |
| Griffin | Ind. | Gibson | Conoco | .8 | 4 | 1 | 2,400 | JS | -- |
| El Dorado | Ks. | Butler | Cities-ERDA | 51 | 8 | 12 | 650 | JS | -- |
| Delaware-Childers | Ok. | Nowata | B & N-ERDA | 10 | 4 | 2 | 620 | JS | -- |
| N. Burbank | Ok. | Osage | Phillips-ERDA | 90 | 16 | 9 | 3,000 | JS | -- |
| Bradford | Penn. | McKean | Pennzoil-ERDA | 16 | 16 | 9 | 1,100 | JS | -- |
| Bradford | Penn. | McKean | Pennzoil | 46 | 25 | 16 | 1,900 | NC | 36 |
| County Reg. | Tx. | Wichita | Mobil | 209 | 20 | 10 | 1,700 | HF | -- |
| Slaughter | Tx. | Hockley | Texaco | 4 | 1 | 4 | 5,000 | HF | -- |
| W. Ranch | Tx. | Jackson | Mobil | 2.5 | 1 | 1 | 5,700 | Term. 11-74 | -- |
| Big Muddy | Wyo. | Converse | Conoco | 5 | 6 | 4 | 3,100 | HF | 70 |
| La Barge | Wyo. | Sublette | Texaco | 1.7 | 1 | 4 | 700 | JS | -- |

NC = nearing completion

JS = just started

HF = half finished

Term. = Terminated

Source: The Oil and Gas Journal, April 5, 1976, pp. 120-121.

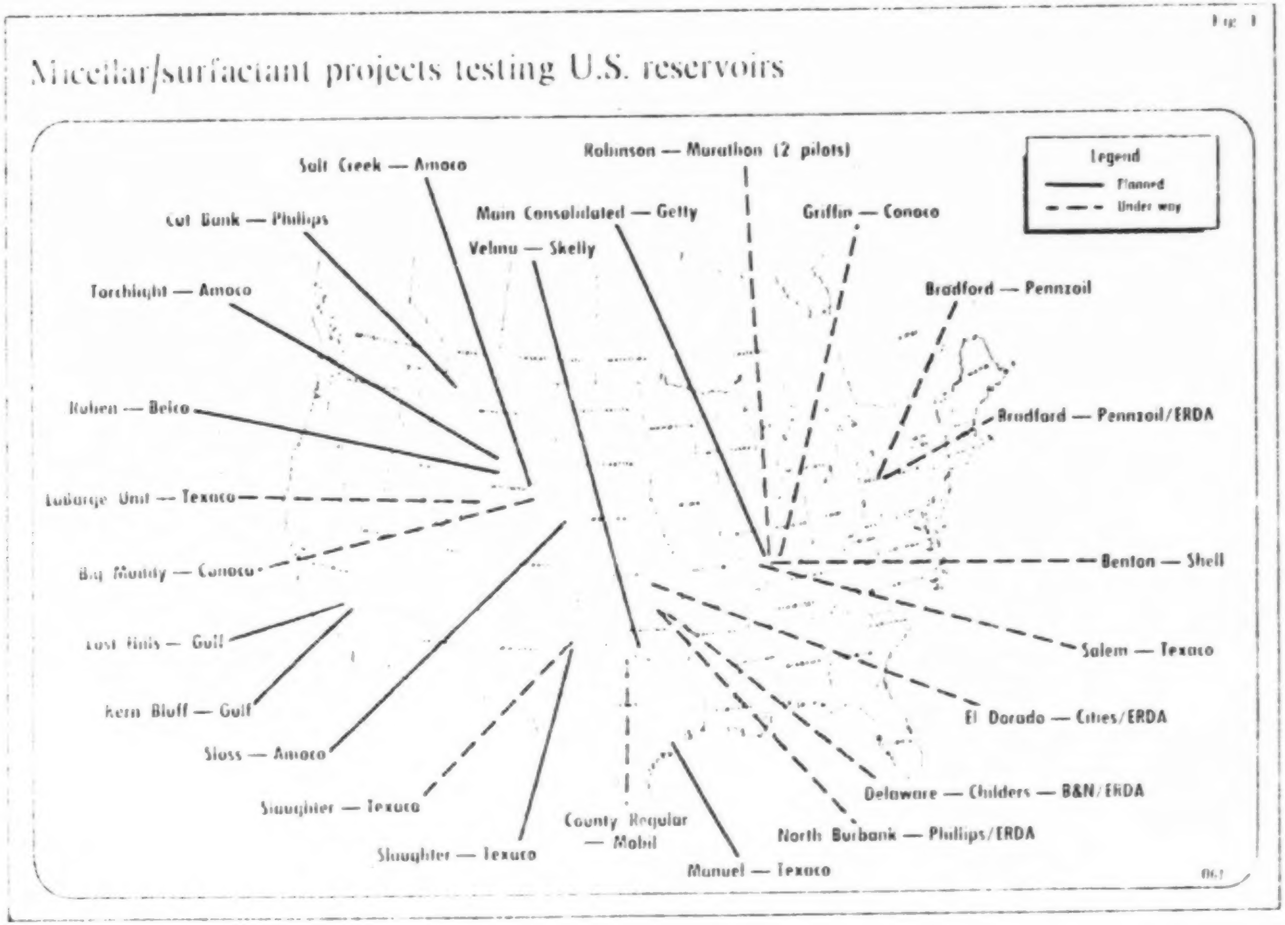
Fig. 1
Micellar/surfactant projects testing U.S. reservoirs
Legend
Planned
Under way
Salt Creek — Amoco
Robinson — Marathon (2 pilots)
Cut Bank — Phillips
Main Consolidated — Getty
Griffin — Conoco
Velma — Skelly
Torchlight — Amoco
Bradford — Pennzoil
Ruben — Belco
Bradford — Pennzoil/ERDA
LaBarge Unit — Texaco
Benton — Shell
Big Muddy — Conoco
Salem — Texaco
Lost Hills — Gulf
El Dorado — Cities/ERDA
Kern Bluff — Gulf
Sloss — Amoco
Delaware — Childers — B&N/ERDA
Slaughter — Texaco
County Regular — Mobil
North Burbank — Phillips/ERDA
Slaughter — Texaco
Manvel — Texaco
061

Figure IV-6. Pilot surfactant recovery projects scheduled for completion during 1976. (The Oil and Gas Journal, April 5, 1976, pp. 120-121.)

extensively in this country as a source of water for irrigation, livestock watering, and human consumption, and some states rely almost exclusively on groundwater-derived water supplies. In many areas of the country some aquifers are already unusable due to natural geochemical contamination, so that the further pollution of aquifers by human activities poses a severe water supply problem.

One important parameter affecting the severity of a well failure at a micellar-polymer project (if such a failure occurs) is the importance of groundwater use for a particular region; i.e., the percent of the region's water supply which is derived from ground water. States which use ground water more heavily would probably be more concerned about potential sources of groundwater impact. Table IV-27 shows the states in which micellar-polymer projects are currently in operation, the number of wells in each state, and the percent of the state's water supply which is derived from ground water.

A number of factors affect probability of well failure, but their quantitative contribution to total failure incidence is impossible to determine. The major factor is age of well. Injection of surfactants for the purposes of tertiary recovery can take place at both old and new wells, and for a number of reasons involving the progressing technology of well construction, older wells tend to be more prone to failure than newer wells. Furthermore, EPA regulations for underground injection control tend to set less stringent permit requirements for existing wells than for new wells, although certain minimum standards of safety apply to all wells used for the purposes of underground injection. The age distribution of wells used for surfactant injection, as compared to the age distribution of wells used for other tertiary recovery techniques, is shown in Table IV-28. The table divides wells into three age categories, (pre-1920, 1921 to 1940, and 1941 and after). It can be seen that the majority of micellar wells fall into the middle age category, as opposed to thermal tertiary recovery (for example), in which the majority of wells are in the "oldest wells" category. The table also reveals relative magnitudes of age-related risk on a region-specific basis.

Produced and injected fluids used in the micellar-polymer process contain high concentrations of surfactants and of organic cosurfactants such as alcohols and phenolics. Each of these chemicals is known to have some impact on beneficial use of ground water, over and above the impact created by the presence of hydrocarbons and trace metals in oilfield brines.

## TABLE IV-27

## GROUNDWATER USE IN MICELLAR-POLYMER RECOVERY AREAS

| STATE | NUMBER WELLS PROJECTION | NUMBER WELLS INJECTION | PERCENT WATER SUPPLY DERIVED FROM GROUNDWATER (1970)[1] |
|---|---|---|---|
| Illinois | 95 | 67 | 7 |
| Indiana | 4 | 1 | 5 |
| Kansas | 8 | 18 | 83 |
| Oklahoma | 20 | 11 | 59 |
| Pennsylvania | 41 | 25 | 4 |
| Texas | 22 | 15 | 34 |
| Wyoming | 7 | 8 | 4 |

---

[1] Geraghty and Miller et al., Water Atlas of the United States (Port Washington, New York: Water Information Center, 1973), plate 32.

## TABLE IV-28

## FRACTION AND NUMBER OF WELLS IN MAJOR OIL FIELDS OF EACH REGION WHERE TERTIARY RECOVERY IS FEASIBLE

| TERTIARY RECOVERY METHOD | DATE OF WELLS | PACIFIC | ROCKIES | NORTH CENTRAL | SOUTH CENTRAL | SOUTH EAST | NORTH EAST | TOTAL |
|---|---|---|---|---|---|---|---|---|
| Micellar | ≤1920 | 20% (512) | 83% (1,656) | 21% (2,580) | 10% (1,421) | 56% (247) | NA | 10% (6,416) |
| | 1921-1940 | 5% (117) | 17% (350) | 63% (7,788) | 88% (12,222) | 71% (3,334) | NA | 67% (23,811) |
| | ≥1941 | 75% (1,893) | NA | 16% (1,920) | 2% (258) | 24% (1,150) | NA | 15% (5,221) |
| Thermal | ≤1920 | 76% (21,820) | 100% (701) | NA | 21% (1,622) | 94% (8,533) | NA | 68% (32,676) |
| | 1921-1946 | 20% (5,593) | NA | 100% (1,920) | 79% (6,090) | 2% (166) | NA | 29% (13,769) |
| | ≥1941 | 4% (1,138) | NA | NA | NA | 4% (383) | NA | 3% (1,521) |
| Carbon Dioxide | ≤1920 | 20% (129) | 21% (540) | NA | 42% (11,772) | 62% (8,886) | NA | 42% (20,727) |
| | 1921-1940 | 14% (90) | 79% (1,995) | 98% (5,227) | 34% (9,461) | 31% (4,067) | NA | 42% (20,840) |
| | ≥1941 | 66% (414) | NA | 16% (53) | 24% (6,579) | 7% (912) | NA | 16% (7,958) |

NA: None or data not available.

Source: Energy Resources, Tertiary Oil Recovery, 1976, p. 156.

Surfactants are known to create taste and odor problems in water supplies, and in addition have a demonstrated toxicity to aquatic and mammalian life. Minimum taste and odor thresholds for some common surfactants used in tertiary oil recovery operations are shown in Table IV-29.

The 1972 U.S. Environmental Protection Agency *Water Quality Criteria* set a limit of 0.5 ppm for surfactants (measured as "methylene blue active substances") in water supplies. The criteria make the following comments on water quality problems associated with surfactants.

> Concentrations of anionic surfactants in water can be determined by means of their reaction with methylene blue dye. Concentrations of less than 0.5 mg/l, as methylene blue active substances (MBAS), do not cause foaming or present serious interference in the defined treatment process and are well below the inferred limit (700 mg/l) of toxicity to humans based on tests on rats fed diets of LAS [linear alkyl sulfonates].

To prevent problems associated with taste, odor, and high toxicity of phenolics and chlorinated phenolics, the EPA has set a maximum limit of 1 μg/l (1 ppb) for phenol levels in public water supplies.

Generally, no specific criteria have been set for the aliphatic alcohols occasionally used as cosurfactants, but published toxicity data suggest that they will not create severe water quality problems.

## TABLE IV-29

## MINIMUM CONCENTRATION OF SURFACTANT REQUIRED TO PRODUCE A PERCEPTIBLE TASTE AND ODOR

| SURFACE ACTIVE AGENT | MIN. CONC. (mg/l) TASTE | ODOR | TYPE OF TASTE OR ODOR |
|---|---|---|---|
| Alkyl aryl sulfonate | 0.6 | 0.7 | Limey, chemical |
| Alkyl aryl sulfonate | 0.4 | 0.3 | Soapy |
| Alkyl sulfate | 3.0 | 0.2 | Solvent |
| Alkyl sulfonate | 1.4 | 0.3 | Bitter, soapy, kerosine |
| Sulfonated amide | 2.5 | 2.0 | Chemical, soapy |

Source: McKee and Wolf, Water Quality Criteria, for the California State Water Quality Control Board, 1963, p. 397

## D. Environmental Impacts Associated with Injected Fluids

### 1. Treated Waters for Waterflood

Quality requirements for water injected into oil-bearing formations fall into two general categories: first, the water should be free of suspended solids or material which can cause plugging of injection wells and resultant drops in pressure; and, secondly, the water must be non-corrosive in order to protect casing and production equipment.

Sources of water include production water from the formation itself and outside sources of water which include surface water of any type and ground water. Since quantities injected can range upward to approximately 25 barrels of water per barrel of oil recovered as in the Big Wall Field in Montana,[1] the water supply should ideally be extensive and inexpensive. Since fields in West Texas, Oklahoma and California are located in water scarce regions, it is not always possible to meet these criteria, especially if the produced water has to be supplemented. With increasing oil prices it is becoming more attractive to invest in facilities capable of treating such unlikely sources as sewage effluent.

Water quality requirements associated with oil production in general have two sets of impacts: an impact due to the treatment facility itself and the impact of the water produced by the facility and injected into the formation.

The major problem that necessitates water treatment is corrosion which can be caused by either chemical or bacterial activity. Corrosion due to chemical action can be counteracted either by treating the water or by changing the metal in contact with the water where possible to a less corrosive material such as fiberglass or cement-asbestos. Chemical corrosion can be reduced by adding a corrosion inhibitor that lays down a protective coating of lining of the pipe. In the oil industry many inhibitors have been used. At the Wilmington Oil Field[2] 13 corrosion inhibitors are now in use. The composition of the inhibitors now in use is proprietary and difficult to define but likely contains compounds that would be deleterious to water quality if they entered the groundwater. Since there has not been much concern about the possibility of this occurring, little has been done categorizing these compounds in terms of effects on surface or ground water.

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[1] State of Montana, Department of Natural Resources and Conservation, Oil and Gas Division, Annual Review for the Year 1974 Relating to Oil and Gas.

[2] "Water-Quality Control Presents Challenge in Wilmington Field," Oil and Gas Journal (August 16, 1976).

Another significant source of corrosion is dissolved oxygen in water which is present in all but the most polluted surface waters. Produced waters originating from the oil formation itself should not contain any oxygen. Adding chemical such as sodium sulfite or bubbling methane gas are two procedures often used to remove dissolved oxygen.

## 2. Disposal of Brine

### 2.1 Introduction

The fluid produced from oil reservoirs generally contains both oil and an aqueous, generally saline solution known as produced water or oilfield brine. The quality of this fluid is primarily a function of the characteristics of the reservoir from which it is drawn and is relatively insensitive to the production technology employed, except to the extent that chemicals (such as surfactants) may have been added to an injection fluid. Produced waters are generally separated from oil at the production facilities in order to obtain a dry, marketable crude oil. After separation from the oil, produced waters must be disposed of in some way, and this disposal can create significant water quality impacts.

Because of the potential toxicity of oilfield brines, only three methods of disposal are recognized as environmentally sound. The most common disposal technique consists of injection into underground formations. Injection can be used purely for disposal purposes, or, in some cases, for the purposes of secondary or tertiary oil recovery. The second technique is reuse of the produced waters, generally either for livestock watering or irrigation, but this is only feasible in the small percentage of fields where the reservoirs are fairly shallow and the produced waters relatively low in total dissolved solids or other potentially toxic substances. The third method, feasible in regions where average rates of evaporation exceed average rates of precipitation, is evaporation of the brines in lined disposal pits. The remaining residue is then either utilized or disposed. These last two methods are restricted in application and account for only a small proportion of the total volume of produced waters generated from oil extraction operations in the United States.

Injection of brines represents a potential environmental impact because of the possibility of contamination of groundwater sources by produced waters. Although Federal and state regulations now exist setting standards for the construction of new wells, the possibility still exists of well failure at both new and old wells and the subsequent leakage of brines through well casings into important aquifers. The magnitude of this problem is suggested by Table IV-30, which shows the numbers of subsurface brine disposal wells in existence in the United States as of 1975.

### 2.2 Regulatory Control of Produced Water Disposal

#### 2.2.1 Safe Drinking Water Act

The requirements for setting terrestrial brine disposal regulations are stated in the Safe Drinking Water Act, PL93-523. This act delegates to the Administrator of the EPA the responsibility for publishing regulations "for the protection of underground sources of drinking water" (Section 1421). Underground injection is defined to endanger drinking water sources if "such injection may result in the presence in underground water which supplies or can reasonably be expected to supply any public water system, of any contaminant, and if the presence of such contaminant may result in such system's not complying with any national primary drinking water regulation or may otherwise adversely affect the health of persons" (Section (d)(2)). Contaminant is defined (Section 1401) as "any physical, chemical, biological, or radiological substance or matter in water," i.e., practically anything but the water molecule.

The Act explicitly requires that any such injection regulation programs set up by the Administrator or the states may not interfere unnecessarily with the production of oil. According to Section 1421, (b)(2)(A): "Regulations of the Administrator under this section for State underground injection control programs may not prescribe requirements which interfere with or impede the underground injection of brine or other fluids which are brought to the surface in connection with oil or natural gas production, or any underground injection for the purpose of secondary or tertiary oil recovery of oil or natural gas, unless such requirements are essential to assure that underground sources of drinking water will not be endangered by such injection."

The Act sets reasonable critieria for variances in Section 1421(c)(2):

## TABLE IV-30

## STATES WHERE OILFIELD BRINES ARE DISPOSED, TOTAL NUMBER OF SUBSURFACE SALT WATER DISPOSAL WELLS (SWDW) AND LARGEST DISPOSAL FACILITIES

| STATE | TOTAL NO. OF SWDW | LARGEST SWDW ($m^3$/day) | SWDW ≥4700 $m^3$/day | SWDW ≥1590 $m^3$/day | REMARKS |
|---|---|---|---|---|---|
| Ala. | 14* | 2,385 | | | |
| Alaska | no data | | | | |
| Ariz. | 4 | 191 | 0 | 0 | |
| Ark. | 421 | 9,221 | 5 | 14 | + bromine plant effluent |
| Calif. | 216 | 25,120 | | | |
| Colo. | 25* | 2,544 | | | |
| Fla. | 5 | 954 | 0 | 0 | |
| Ill. | no data | | | | |
| Ind. | 325 | 159 | 0 | 0 | |
| Kans. | 3,150 | 3,180 | | 2** | |
| Ky. | 60** | 111 | 0 | 0 | |
| La. | 1,304 | | | | average SWDW is 217 $m^3$/day |
| Mich. | 522 | 318 | 0 | 0 | average SWDW is 32 $m^3$/day |
| Miss. | 370 | 1,113 | 0 | 0 | |
| Mont. | 200 | 239 | 0 | 0 | |
| Nebr. | 3 | 135 | 0 | 0 | |
| Nev. | – | – | 0 | 0 | only 7 producing wells for State |
| N. M. | 300 | 2,703 | 0 | 4 | |
| N. Y. | – | – | 0 | 0 | |
| N. D. | 62 | 318 | 0 | 0 | |
| Ohio | 28* | 318 | 0 | 0 | |
| Okla. | 4,900 | | | | |
| Pa. | – | – | 0 | 0 | most of this is by ponding |
| S. D. | – | – | 0 | 0 | ponding used |
| Texas | 7,173** | | | | number of SWDW permitted from 1950–1971 |
| Utah | 3** | 143 | 0 | 0 | |
| W. Va. | 95** | 159 | 0 | 0 | |
| Wyo. | 19* | | | | |

* Salt water disposal systems that may have more than one salt water disposal well per system.

** Approximate.

Source: A.G. Collins, Geochemistry of Oilfield Waters (New York: Elsevier Co., 1975), p. 412.

> The Administrator may, upon application of the Governor of a State which authorizes underground injection by means of permits, authorize such state to issue one or more temporary permits if...the State finds...that technology to permit safe injection of fluid in accordance with the applicable underground injection control program is not generally available, taking costs into consideration, or that the injection of the fluid would be less harmful to health than the use of other available means of disposing of waste or producing the desired product; and that the available technology or other means have been employed and will be employed to reduce the volume and toxicity of the fluid and to minimize the potentially adverse effect of the injection on public health.

### 2.2.2 UIC (Underground Injection Control) Regulations

EPA, pursuant to the authority granted it by the Safe Drinking Water Act, has proposed a set of regulations designed to prevent the endangerment of underground drinking water sources by underground injection operations, including brine disposal (40CFR Part 146).

In order to provide an adequate margin of safety for the protection of drinking water supplies, the regulations adopt a very broad definition of the term "endangerment". According to the regulations, injection "endangers" an underground drinking water supply if:

> (1) such injection may make it necessary for a public water system using an underground drinking water source to increase treatment of the water, or (2) if such injection might make it necessary for a public water system which might use the source in the future to use more extensive treatment of the water than would otherwise have been necessary, or (3) if such injection may otherwise adversely affect the health of persons such as by adding a substance that would make water from the source unfit for human consumption.[3]

The regulations go on to note that underground water supplies will generally be defined as "potential" drinking water sources, and therefore will fall within the scope of the regulations, if such supplies have total dissolved solids levels of less than 10,000 mg/l. However, the regulations do permit the states to decide that certain aquifers having a TDS level of less than 10,000 mg/l will not be protected, on the grounds that "they are severely contaminated or are located in such a way that use as drinking water is impracticable. The state must demonstrate by compelling evidence that an aquifer is and will continue to be unsuitable as a source of drinking water."

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[3] U.S. Environmental Protection Agency, "Proposed Regulations for State Underground Injection Control Program," in the Federal Register, 40 CFR Part 146, July 13, 1976.

The regulations further note that part (3) of the definition of endangerment given above will include not only toxic pollution of water supplies but also contamination which would make the water unfit for human consumption by giving it objectionable taste, odor, or color, and thereby forcing the use of an alternative water source of poorer quality.

Special provisions are made in the regulations to prevent unnecessary interference with oil or gas production. The regulations allow variances to be granted to injection operations associated with oil and gas production if "the operator clearly demonstrates that (1) the requirement would stop or substantially delay oil or natural gas production at his site; and (2) the requirement is not necessary to assure the protection of an existing or potential source of underground drinking water." The burden of proof here is clearly on the operator of the oil production project, and he must explicitly demonstrate that his operations will not degrade the quality of existing or potential underground drinking water sources.

The regulations note that "it is clear from the °Safe Drinking Waterl Act and the legislative history of the SDWA that Congress intended that the states exercise primary enforcement responsibility for the protection of underground sources of drinking water to the extent possible;" accordingly, they provide only general guidelines whereby the states can formulate their own UIC programs. All states must submit proposed UIC programs to the Administrator of the EPA for approval. If no plan is submitted by the state, or if a state program proves inadequate in some respects or inconsistent with general EPA UIC guidelines, then the regulations permit the Administrator to prescribe a program for the state or to modify or administer certain selected portions of the state's programs. States will assume "primary enforcement authority" of their own UIC regulations only if the entirety of the proposed program is approved by the Administrator. The regulations state that for approval by the Administrator, state programs must meet the following minimum requirements:

(A) shall prohibit, effective three years after the date of the enactment of this title, any underground injection in such State which is not authorized by a permit issued by the State (except that the regulations may permit a State to authorize underground injection by rule);

(B) shall require (i) in the case of a program which provides for authorization of underground injection by permit, that the applicant for the permit to inject satisfy the State that the underground injection will not endanger drinking water sources, and (ii) in the case of a program which provides for such an authorization by rule, that no rule may be promulgated which authorizes any underground injection which endangers drinking water sources;

(C) shall include inspection, monitoring, recordkeeping, and reporting requirements; and

(D) shall apply (i) as prescribed by Section 1447(b), to underground injections by Federal agencies, and (ii) to underground injections by any other persons whether or not occurring on property owned or leased by the United States.[4]

In addition, specific requirements are set for certain aspects of well construction, including surface casing and tubing and packer requirements.

### 2.2.3 Regulations Governing Offshore Disposal of Produced Waters

Regulations governing the disposal of treated oilfield brines by discharge into coastal waters were created under the authority of the effluent limitations guidelines program of EPA. The guidelines were designed to minimize toxic impacts on coastal ecosystems as a result of brine disposal.

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[4] U.S. Environmental Protection Agency, "Proposed Regulations for State Underground Injection Control Program."

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The effluent guidelines program fulfills the responsibility of EPA under Public Law 92-500 (the Federal Water Pollution Control Act Amendments of 1972) to set BPCTCA (Best Practicable Control Technology Currently Available) and BATEA (Best Available Technology Economically Achievable) regulations for all industrial dischargers in U.S. waters, including coastal waters. The proposed effluent guidelines for the oil and gas extraction industry's offshore segment recognize two categories of offshore production platforms: near offshore and far offshore (inside and outside of the 3-mile limit, respectively). The BATEA regulations for near offshore waters require zero discharge of oil, which can be achieved either by reinjection or else by piping of the produced waters onto the shore or else out into far offshore waters. For far offshore platforms, the only BATEA requirement is for treatment of brines to bring oil levels down to an average of 30 ppm. The regulations do not require reduction of levels of toxic trace metals in brines.

Regulations similar to the near offshore regulations are being considered for nearshore platforms (i.e., those lying in coastal bays and inlets), but these have not been officially proposed at this time.

### 2.2.4 Summary

Federal regulations now exist governing the disposal of produced waters from both terrestrial and offshore oil production platforms. The terrestrial disposal regulations are designed to protect underground drinking water supplies from contamination by toxic constituents of produced waters, while the offshore regulations are designed primarily to protect coastal ecosystems. Disposal operations must take place within the framework of these existing Federal regulations.

## 2.3 Technology of Produced Water Separation, Treatment, and Disposal

### 2.3.1. Oil/Water Separation

Produced fluids generally consist of a mixture of oil, water, and natural gas. These components are generally separated at the production facilities in order to create marketable oil and natural gas and produced water which can be safely injected. The separation process is shown schematically in Figure IV-7. Since oil and water are immiscible,

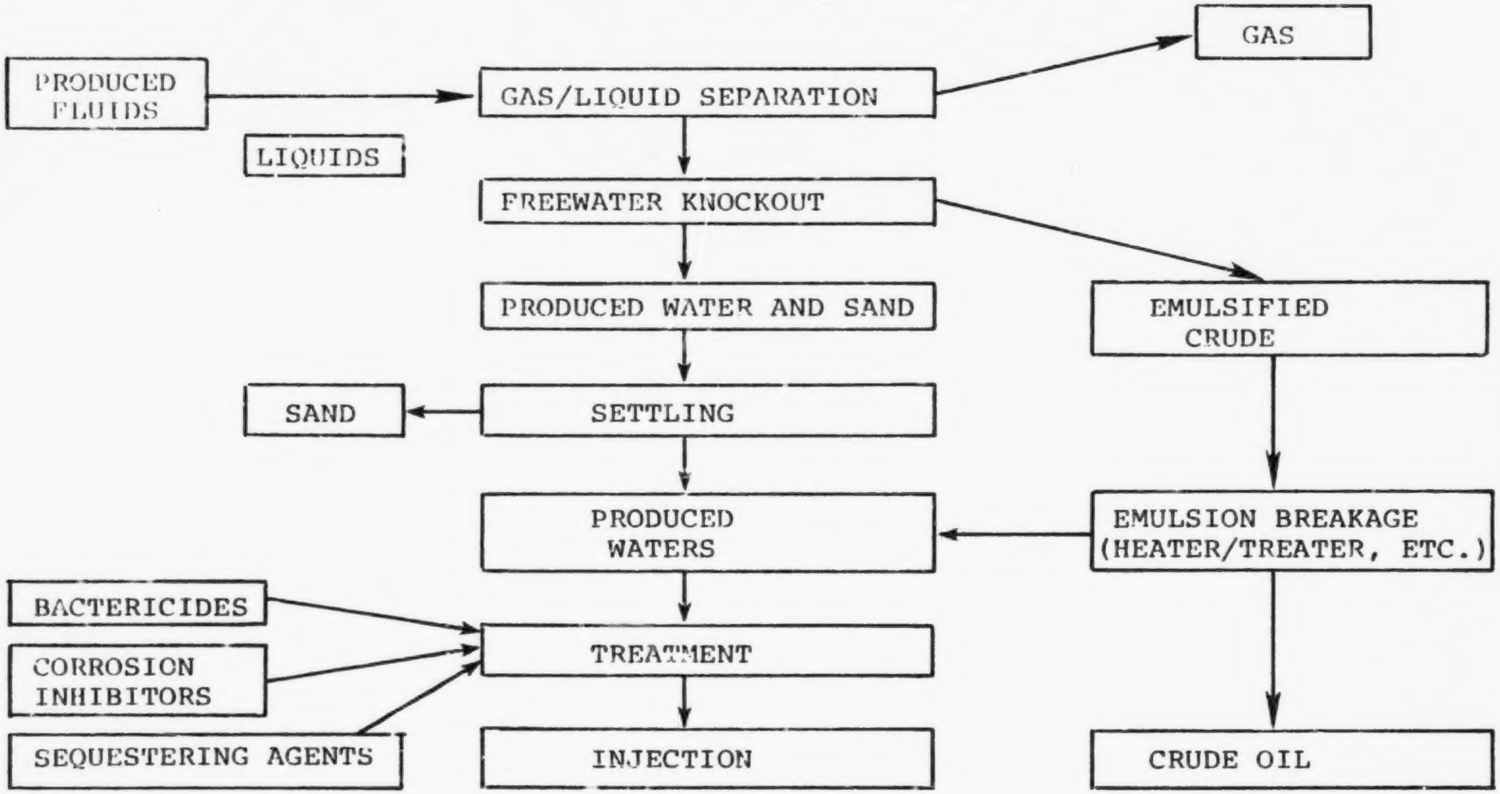
PRODUCED FLUIDS
GAS/LIQUID SEPARATION
GAS
LIQUIDS
FREEWATER KNOCKOUT
PRODUCED WATER AND SAND
EMULSIFIED CRUDE
SAND
SETTLING
PRODUCED WATERS
EMULSION BREAKAGE (HEATER/TREATER, ETC.)
BACTERICIDES
CORROSION INHIBITORS
SEQUESTERING AGENTS
TREATMENT
INJECTION
CRUDE OIL

Figure IV-7. Schematic diagram of separation processes for produced fluids.

a preliminary separation of these two fluids can be achieved simply by placing the mixture in a settling tank and skimming oil from the top of the tank as it separates from the water. This process is known as freewater knockout. After knockout, the oil and water may still be contaminated with significant quantities of each other in the form of stable emulsions. These emulsions may be "broken" by thermal or electric treatment.

Emulsified oil/water mixtures remaining after freewater knockout are passed to another vessel called a heater-treater, electric dehydrator, gun barrel, or wash tank, depending upon the separation method used.[5] The liquid in this vessel consists of three layers: an emulsified oil/water mixture, a layer of relatively dry oil, and a layer of relatively oil-free water. The vessel will generally contain sensing units to detect the oil/water/emulsion interfaces and control the release of pure oil and water from the top and bottom of the vessel. Separation of pure oil and water from the emulsion is facilitated by chemical treatment, heat, and the use of electric charges. A diagram of a vertical heater-treater is shown in Figure IV-8.

### 2.3.2 On-Shore Brine Disposal

In the early days of oil extraction, produced waters were generally disposed of with little regard for possible environmental impacts. According to Collins:[6] "Until about 1930, the oilfield waters were disposed into local drainage, frequently killing fish and even surface vegetation." It was only after about 1930 that brine evaporation or reinjection became standard practice for brine disposal. Even then, however, little care was taken to prevent contamination of aquifers by injected brines, and evaporation frequently took place in unlined pits which allowed percolation of brine into shallow aquifers.

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[5] U.S. Environmental Protection Agency, Effluent Guidelines Division, Office of Waste and Hazardous Materials, Draft Development Document for Effluent Limitations Guidelines and New Source Performance Standards for the Oil and Gas Extraction Point Source Category, October 1974, p. III-15.

[6] A.G. Collins, Geochemistry of Oilfield Waters (New York: Elsevier Company, 1975), p. 3.

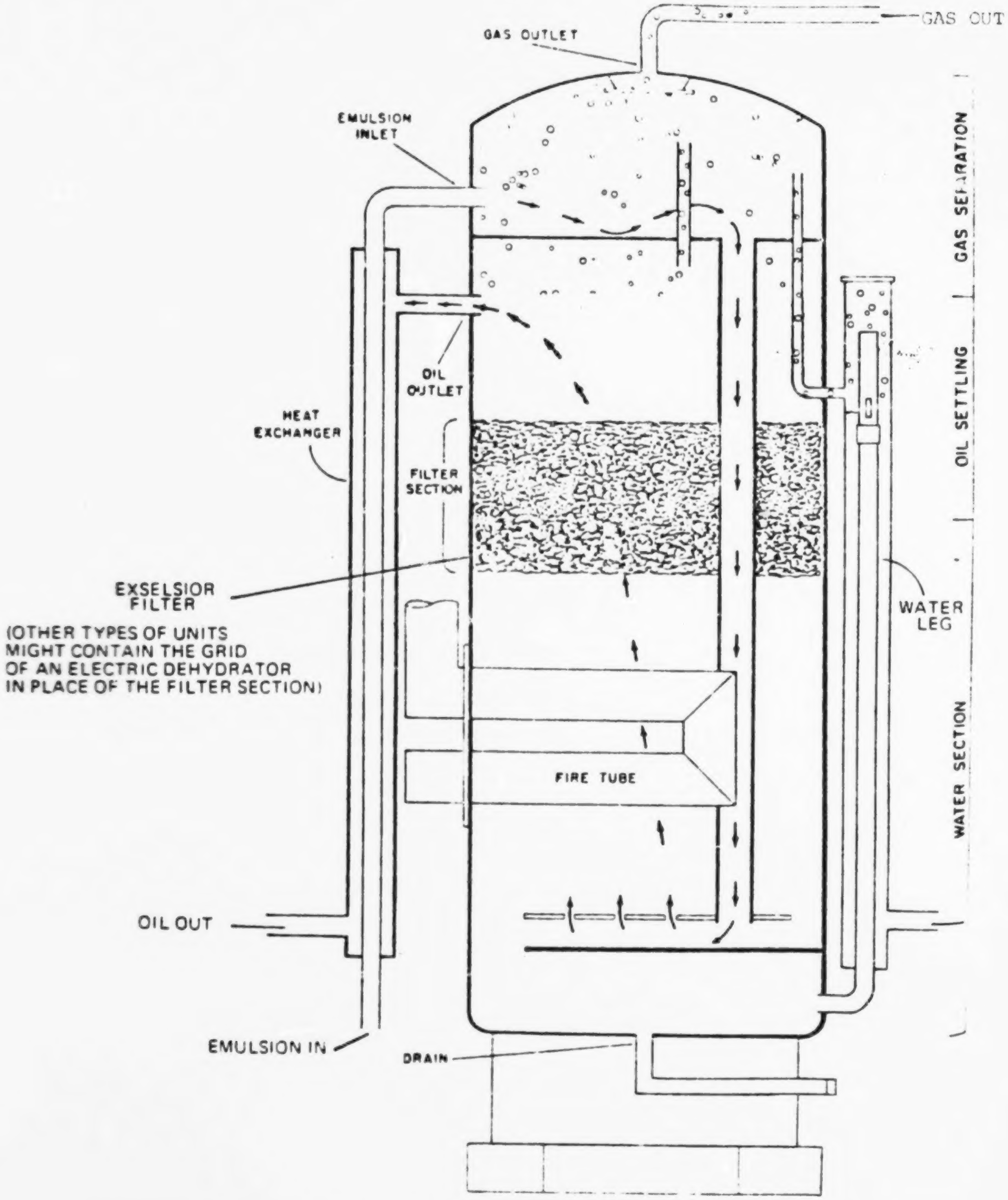
GAS OUT
GAS OUTLET
EMULSION INLET
GAS SEPARATION
OIL SETTLING
WATER SECTION
OIL OUTLET
HEAT EXCHANGER
FILTER SECTION
EXSELSIOR FILTER
(OTHER TYPES OF UNITS MIGHT CONTAIN THE GRID OF AN ELECTRIC DEHYDRATOR IN PLACE OF THE FILTER SECTION)
WATER LEG
FIRE TUBE
OIL OUT
EMULSION IN
DRAIN

Figure IV-8. Vertical heater-treater. (U.S. Environmental Protection Agency, Draft Development Document for Effluent Limitations Guidelines and New Source Performance Standards for the Oil and Gas Extraction Point Source Category, October 1974, p. III-16.)

Today only three methods of brine disposal are generally recognized as being environmentally sound (see discussion under Section D.2.1 above), and two of these have very limited usefulness in the majority of oil fields. The primary method of brine disposal remains injection into subsurface formations, either for the purpose of disposal alone, or else for use in waterflooding applications.

Only a very small proportion of produced waters are suitable for livestock watering or agricultural irrigation. In some Rocky Mountain production areas, produced waters have a fairly low TDS content and are commonly used for livestock watering. Another example is the Kern County oilfield in California, where produced waters are used for irrigation.

In very dry areas, evaporation ponds present a possible solution to the brine disposal problem. In order for such ponds to be feasible, annual evaporation rates must exceed annual precipitation rates. According to EPA's Development Document for the Oil and Gas Extraction Point Source Category:

> In some of the Nation's arid and semiarid western and southwestern oil and gas producing areas, use of [evaporation ponds] is an acceptable, although limited practice. The surface pit, pond, or reservoir can only be used where evaporation rates greatly exceed precipitation and the quantity of emplaced water is small. The pit or pond is ordinarily located in flat to very gently rolling ground and not within any natural drainage channel to avoid danger of flooding by overland flow of water following precipitation. Pit facilities are normally lined with impervious materials to prevent seepage and subsequent damage to fresh surface and subsurface waters. Linings may range from reinforced cement group to flexible plastic liners. In areas where the natural soil and bedrock are high in bentonite, montmorillonite, and similar clay materials which expand upon being wetted, no lining is normally applied and sealing depends on the natural swelling properties of the clays. All pits are normally enclosed to prohibit or impede access.[7]

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[7] U.S. Environmental Protection Agency, Draft Development Document, p. VII-29.

Both evaporation and beneficial reuse are feasible at only a relatively small number of oil fields, however, and reinjection remains the standard brine disposal practice. In addition to serving as a brine disposal method and as an oil recovery enhancement technique, reinjection may be useful in some areas to control land subsidence.

Injected brines must be free of suspended solids, to prevent clogging of formations receiving the brine, and they must be chemically compatible with waters already existing in the injection site, in the sense that they should not react with local brines to form precipitates which might clog the formation. In addition, the injected waters must be relatively sterile to prevent the formation of bacterial slimes which might interfere with continued injection.

## 2.4 Characteristics of Produced Waters

Produced waters present a potential environmental threat because they contain toxic trace heavy metals and oil hydrocarbons which, if introduced into groundwater supplies, could prevent the beneficial use of these supplies for purposes such as agricultural irrigation, livestock watering, and as the source of public drinking water supply systems. This section deals with the chemical constituents of produced water; in a subsequent section, the ways in which these constituents might interfere with beneficial use of ground waters will be discussed.

### 2.4.1 Quantities of Produced Waters

Produced waters can range from less than 1 to over 98 percent of produced fluids, on a volume basis. Generally, older wells, from which substantial quantities of oil have already been extracted, will have lower oil/water ratios than comparatively unexploited fields. According to EPA's Development Document: "In some formations, water is produced with the oil and gas in early stages of production; in others, water is not produced until the producing formation is significantly depleted; in still other types of formations, water is never produced." Collins notes that total production in the United States in 1970 amounted to 23.9 million barrels of water and 9.55 million barrels of oil daily. Thus, the average volume of produced water was 2.5 barrels per barrel of oil produced.

### 2.4.2 Salinity of Produced Waters

Produced waters from most oil reservoirs are highly saline. Typical TDS ranges for oilfield brines from some states are shown in Table IV-31. Collins reports that the chloride content of produced waters ranges from 20,000 to 200,000 ppm; using the relationship

$$\text{Salinity} = 1.80655 \text{ (chloride)}$$

typical salinities ranging from 360 to 360,000 parts per million (ppm) are obtained (typical seawater salinities are in the range 25,000 ppm to 30,000 ppm).

Data from Collins on total dissolved solids levels in brines from 11 states[8] suggest an average TDS level of 108,225 ppm.

TABLE IV-31

TOTAL DISSOLVED SOLIDS LEVELS IN PRODUCED WATERS

| STATE | TDS (ppm) |
|---|---|
| Colorado | 333 - 10,795 |
| Montana | 350 - 15,230 |
| Utah | 373 - 120,395 |
| Wyoming | 291 - 276,290 |

Source: EPA, Draft Development Document.

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[8] Collins, Geochemistry of Oilfield Waters, p. 413.

### 2.4.3. Trace Metal Levels of On-Shore Produced Waters

The levels of some common inorganic contaminants, primarily trace metals, in produced waters are shown in Table IV-32.

TABLE IV-32

LEVELS OF INORGANIC CONSTITUENTS IN PRODUCED WATERS

| SUBSTANCE | CONCENTRATION (ppm) |
|---|---|
| Li | generally 2 - 10 |
| Cl | 20,000 - 200,000 |
| Na | 10,000 - 50,000 |
| K | 50 - 2,000 |
| Be | 0.02 - 0.2 |
| Mg | 50 - 5,000 |
| Ca | 2,000 - 3,000 |
| Ba | 10 - 100 |
| Fe | 0 - 1,000 |
| Cu | 0.5 - 3.0 |
| Zn | 0 - 500 |
| Hg | 0.0 - 0.15 |
| Pb | 0.0 - 100 |
| Cd | 0.0 - 0.001 |
| B | 0.0 - 100 |
| As | 0.0 - 10 |

Source: Collins, Geochemistry of Oilfield Waters, pp. 133-192.

Levels of these constituents in produced waters are highly site specific, and variable even within single sites. According to Collins:[9] "Subsurface waters associated with petroleum are subjected to forces that promote mixing and homogeneity, but the assuption cannot be made that they are so well mixed that no attention to sampling technique is required."

### 2.4.4 Hydrocarbons in Produced Waters

Untreated brines can contain several hundred to over 1,000 parts per million of oil-derived hydrocarbons. Since the solubility of oil hydrocarbons in water is approximately 25 ppm, most of these hydrocarbons will be suspended.[10] Even if suspended contamination is removed from oilfield brines (by, for example, entrapment in interstices of underground formations), then approximately this level (25 ppm) of residual hydrocarbons will remain. This 25 ppm constitutes what is known as the "water-soluble fraction" of crude oil. Experiments by Anderson[11] have shown that this water-soluble fraction is enriched from 15 to 100 times in aromatic constituents as compared to the parent crude oil (this enrichment factor is calculated as the aromatic to paraffin ratio in the water-soluble fraction divided by the same ratio in crude oil). This is significant since the aromatic components of crude oil are among the most toxic of the oil hydrocarbons. Levels of some hydrocarbons in a water-soluble fraction of crude oil are shown in Table IV-33. Levels of various hydrocarbons in an oil/water dispersion, which might more accurately represent the composition of a crude oil containing significant suspended oil contamination, are shown in Table IV-34. Anderson's paper, unfortunately, contains data on a single U.S. crude sample.

### 2.4.5 Treatment of Oilfield Brines

Treatment of produced waters prior to injection is generally done not to reduce potential environmental impact

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[9] Collins, Geochemistry of Oilfield Waters, p. 7.

[10] See Anderson et al., "Characteristics of Dispersion and Water-Soluble Extracts of Crude and Refined Oils," Marine Biology 27 (1974): 75-88.

[11] Anderson et al., "Characteristics of Dispersion and Water-Soluble Extracts," 1974.

## TABLE IV-33

## HYDROCARBON CONCENTRATIONS OF CRUDE OIL WATER-SOLUBLE FRACTIONS

(ppm)

| COMPOUND | SOUTH LOUISIANA CRUDE OIL |
|---|---|
| **ALKANES** | |
| Ethane | 0.54 |
| Propane | 3.01 |
| Butane | 2.36 |
| Isobutane | 1.69 |
| Pentane | 0.49 |
| Isopentane | 0.70 |
| Cyclopentane + 2-Methylpentane | 0.38 |
| Methylcyclopentane | 0.23 |
| Hexane | 0.09 |
| Methylcyclohexane | 0.22 |
| Heptane | 0.06 |
| $C_{16}$ n-Paraffin | 0.012 |
| $C_{17}$ n-Paraffin | 0.009 |
| TOTAL $C_{12}$-$C_{24}$ n-paraffins | 0.089 |
| **AROMATICS** | |
| Benzene | 6.75 |
| Toluene | 4.13 |
| Ethylbenzene + m-, p-Xylenes | 1.56 |
| o-Xylene | 0.40 |
| Trimethylbenzenes | 0.76 |

## TABLE IV-33 (CONT.)

| COMPOUND | SOUTH LOUISIANA CRUDE OIL |
|---|---|
| AROMATICS (CONT.) | |
| Naphthalene | 0.12 |
| 1-Methylnaphthalene | 0.06 |
| 2-Methylnapthalene | 0.05 |
| Dimethylnaphthalenes | 0.06 |
| Trimethylnaphthalenes | 0.008 |
| Biphenyl | 0.001 |
| Methylbiphenyls | 0.001 |
| Dimethylbiphenyls | 0.001 |
| Fluorene | 0.001 |
| Methylfluorenes | 0.001 |
| Dimethylfluorenes | 0.001 |
| Dibenzothiophene | 0.001 |
| Phenanthrene | 0.001 |
| Methylphenanthrenes | 0.002 |
| Dimethylphenanthrenes | 0.001 |
| TOTAL SATURATES | 9.86 |
| TOTAL AROMATICS | 13.90 |
| TOTAL DISSOLVED HYDROCARBONS MEASURED | 23.76 |

Source: Anderson et al., "Characteristics of Dispersion and Water-Soluble Extracts of Crude and Refined Oils," Marine Biology 27(1974): 75-88.

## TABLE IV-34

## HYDROCARBON COMPOSITION OF AQUEOUS PHASE OF 1,000 ppm OF OIL-IN-WATER DISPERSIONS[a]

| HYDROCARBON | SOUTH LOUISIANA |
|---|---|
| $C_{12}-C_{24}$ n-paraffin | 1,988 |
| Tri- and tetra-methylbenzenes | 135 |
| Naphthalene | 64 |
| 1-Methylnaphthalene | 40 |
| 2-Methylnaphthalene | 46 |
| Dimethylnaphthalenes | 108 |
| Trimethylnaphthalenes | 56 |
| Phenanthrene | 34 |
| Methylphenanthrenes | 20 |
| TOTAL N-PARAFFINS | 1,988 |
| TOTAL AROMATICS | 506 |
| TOTAL HYDROCARBONS MEASURED | 2,494 |

[a] All concentrations expressed in ppb.

Source: Anderson et al., "Characteristics of Dispersion and Water-Soluble Extracts," 1974, pp. 15-88.

but rather to prevent corrosion, scaling, or growth of bacterial slimes in injection wells. According to the EPA Development Document: "Current industry practice is to apply minimal or no treatment to the water prior to disposal. If water destined for disposal requires treatment, it is usually confined to minimal application of a corrosion inhibitor and bactericide; a sequestering agent may be added to waters having scaling tendencies...Chemicals are generally added at about 10 to 50 ppm." Addition of these chemicals will increase, rather than decrease, the potential water quality problems resulting from brine injection.

## 3. Possible Impacts of Injected Waters on Groundwater Quality

### 3.1 Introduction

Ground water is held in permeable layers of sand (aquifers) separated from each other and from the surface by less permeable layers (aquicludes). Freshwater (less than 1,000 mg/l total dissolved solids) occurs in strata closer to the surface, with brackish water in deeper aquifers.

Ground water supplies a significant portion of the water supply needs of the United States (see Figure IV-9, which shows percent of water supply obtained for ground water in each of the states). Furthermore, in many areas of the country aquifers are already significantly contaminated as a result of natural geochemical processes.[12] Therefore, it is particularly important to preserve the quality of the portion of ground water which is not naturally contaminated and which can be used as a source of public water supplies.

Groundwater contamination is particularly serious because it is long lasting, difficult to trace, and may be very far reaching. Once a layer of permeable sand has been polluted, it may be years before dilution and percolation clear the contaminant away. Although the actual rate of flow varies among aquifers, 200 feet per year has been suggested as a reasonable rate.[13] At this rate of flow, 260 years would be required to clear an aquifer 10 miles from a river. Some aquifers flow as slowly as 20 ft/yr, and would, therefore, require even longer to cleanse naturally.

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[12] See U.S. Environmental Protection Agency, Groundwater Pollution in the South Central States, EPA-R2-73-268, June 1973.

[13] A.G. Collins, Chemical Applications in Oil and Gas Well Drilling and Completion Operations, for the U.S Bureau of Mines, 1975.

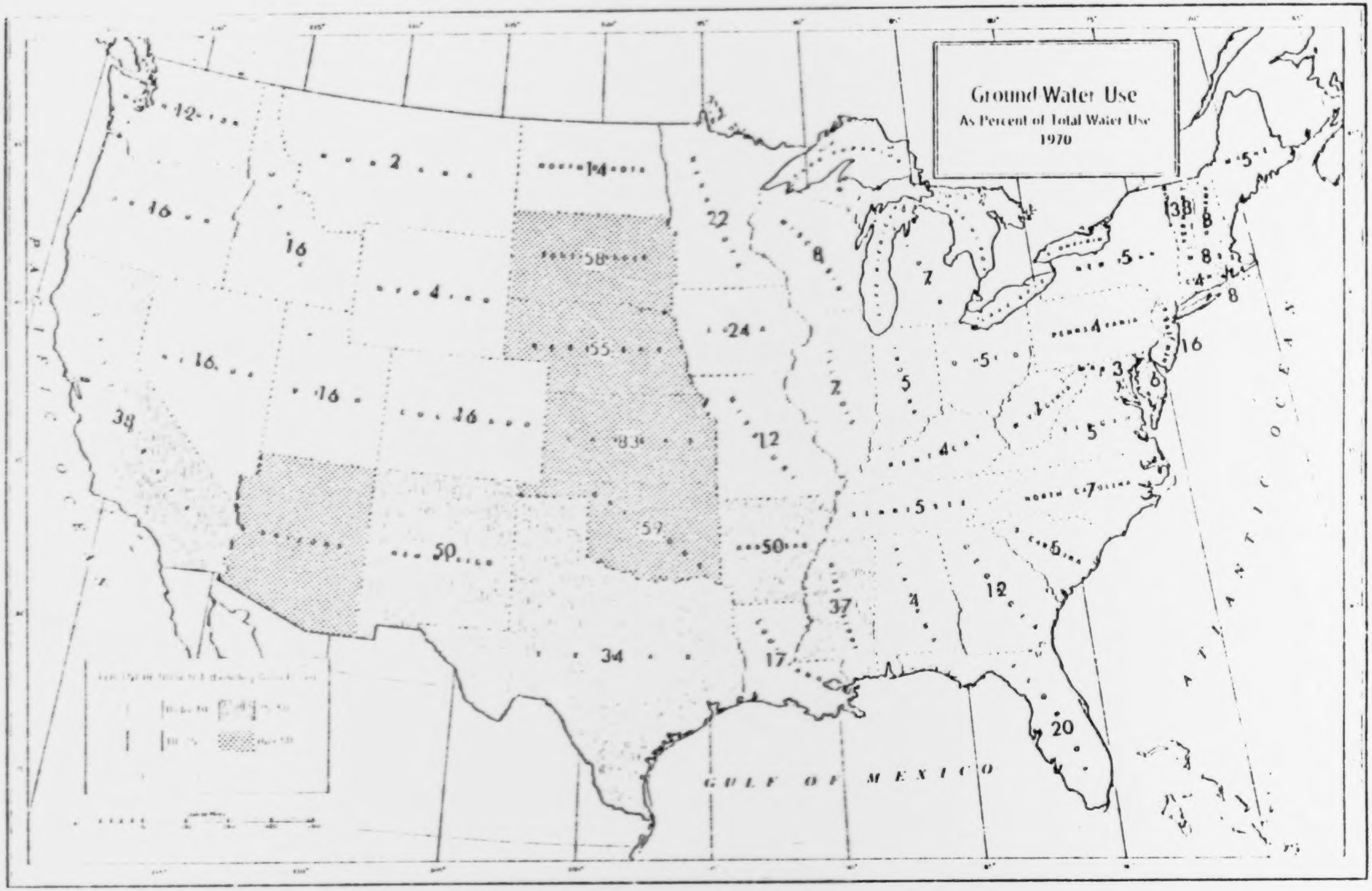
Ground Water Use
As Percent of Total Water Use
1970
12
2
14
16
16
58
22
8
7
5
38
8
8
4
8
4
24
16
16
55
16
16
5
5
7
3
6
38
1
5
12
83
4
7
5
59
50
50
6
12
37
4
34
17
20
GULF OF MEXICO
PACIFIC OCEAN
ATLANTIC OCEAN

Figure IV-9. Groundwater use as percent of total water use, 1970. (Geraghty and Miller et al., Water Atlas of the United States (Port Washington, New York: Water Information Center, 1973), Plate 32.)

Three important beneficial uses of ground water will be considered in this section: use for livestock watering, use for irrigation, and use as the source of a public water supply system.

### 3.2 "Safe" Levels of Brine Constituents in Groundwater Supplies

Two sets of regulatory standards can be applied to the quality of drinking water. The first is applicable only to aquifers used as the source of drinking water supply systems and consists of EPA'a Primary Drinking Water Regulations. These regulations set maximum permissible levels of a number of organic and inorganic contaminants in waters used as the source of drinking water supply systems. The second are EPA's Water Quality Criteria. These are a set of maximum recommended levels for a number of contaminants in water supplies used for a variety of particular beneficial uses (e.g., maintenance of freshwater aquatic populations, recreation, irrigation). Although they have no regulatory force, they generally form the basis for the water quality standards by which each of the individual states regulate the quality of their own waters. Although the criteria were originally intended for application to surface waters, many of the beneficial use categories overlap those for which ground water may be used.

Maximum permissible levels for brine contaminants set in EPA Water Quality Criteria for irrigation waters, EPA Water Quality Criteria for waters used for livestock watering, and in the Primary Drinking Regulations, are shown in Table IV-35.

### 3.3 "Safe" Levels of Chemical Additives Used in Oil Recovery

All advanced oil recovery techniques employ a variety of chemicals to fulfill a multitude of functions. In micellar-polymer flooding, for example, chemicals such as surfactants, polymers, and cosurfactants are regularly used while other chemicals are often used on a site-specific basis to control corrosion, adjust pH, and control algal and bacterial growths.

## TABLE IV-35

## RECOMMENDED LEVELS OF SOME BRINE CONSTITUENTS IN GROUND WATER
(mg/l)

| CONSTITUENT | AGRICULTURE | LIVESTOCK | DRINKING |
|---|---|---|---|
| As | 0.1 | 0.2 | 0.05 |
| Ba | -- | -- | 1.0 |
| Cd | 0.01 | 0.05 | 0.01 |
| Cr | 0.1 | 1.0 | 0.05 |
| Pb | 5.0 | 0.1 | 0.05 |
| Hg | -- | 0.001 | 0.002 |
| Ag | -- | -- | 0.05 |
| Be | 0.1 | -- | -- |
| Cu | 0.2 | 0.5 | 1.0 |
| Fe | 5.0 | -- | 0.3 |
| Li | 0.075 | -- | -- |
| Ni | 0.2 | -- | -- |
| $Cl^-$ | -- | -- | 250. |

Source: U.S. Environmental Protection Agency, Water Quality Criteria, 1972, 1973, and 1975 editions, and National Interim Primary Drinking Water Regulations, Federal Register, December 24, 1975, pp. 595 66 ff.

A list of representative surfactants is presented in Appendix L (Table L-1). For each of the organic surfactants used in advanced oil recovery, maximum permissible levels have been set in the EPA Water Quality Criteria. They are 0.2 mg/liter for aquatic life and 0.5 mg/liter for drinking water.

## 4. Sources of Groundwater Contamination

Groundwater contamination can occur by the following mechanisms:

- Leaching or seepage from surface spills
- Well failure
- Changes in the oil-bearing formations

Surface contamination of groundwater aquifers can be due to infiltration and percolation of spilled chemicals into the ground water and seepage from brine disposal pits. The problem of surface spillage is a phenomenon which is easily detectable and preventable. It is felt that the high cost of the chemicals, the ease of detection, and the availability of suitable control mechansisms all serve to minimize the potential for wid spread groundwater contamination from this source.

Leaching of chemical residuals is another source of pollution. It is not easily detectable, nor is it easily controllable by artificial means.

This mechanism is, however, controlled by natural forces which tend to minimize the potential impacts. The amount of leaching is dependent on the amount of excess rainfall over evaporation, while the movement of the pollutant through the soil matrix depends on such forces as microbial degradation, chemical and microbial immobilization and mineralization, and surface adsorption effects.

Many states have recently recognized the danger of seepage from brine disposal pits and require that all disposal pits be impervious. The result has been a dramatic reduction in the amount of new pollution from this source. Of the complaints concerning brine seepage in Texas Railroad Commission District III since this law went into effect in 1973, most have been traced to continuing seepage from earlier disposal. The difficulty with brine seeps and chemical spills, as with groundwater pollution in general, is their longevity. The risk of chemical spills and seeps is difficult to quantify because many site-specific factors such as operator skill, systems design and construction, modes of shipment, and weather, will interact at each location. Spills which do occur may have long lasting effects on ground water.

Figure IV-10 shows a diagram of a producing well and the possible routes by which injected or produced fluids can leak into water-bearing strata.

The well bore is lined with metal casing which is cemented to the sides of the hole. Surface casing may be installed near the well head to keep the hole clear and to protect shallow freshwater aquifers. Production casing runs the length of the well. A packer set inside the casing seals off the well just above the oil-bearing system. Fluids pass through tubing which is suspended inside the casing and which passes through the packer. The result is a multiple shield between groundwater supplies and oilfield fluids. Despite these elaborate precautions, the well may provide communication among strata for fluids.

Cross-contamination of ground water is due to movement of pollutants from one subsurface aquifer which is used for brine disposal or oil production to another aquifer which is a source of potable ground water. This can occur as a result of man-made effects such as increases in pressure or temperature that can cause fissures.

Groundwater contamination is more of a problem in regions which derive significant fractions of their water supply from groundwater sources. Table IV-36 shows levels of oil production in several states together with statistics on percent of total water supply in each of those states which is derived from groundwater sources.

Evolving EPA guidelines and regulations for reinjection, mandated under the Safe Drinking Water Act, should, in the future, tend to mitigate problems arising in this area. Regions relying on a single aquifer could apply complete restrictions on any reinjection that could pollute that aquifer.

Similarly, the development of Spill Control and Countermeasure Plans, as mandated by the Water Pollution Act (PL 92-500), should mitigate problems arising from accidental spills. The appropriate regulations (40 CFR 112) prescribe standards for both equipment configurations and for housekeeping and operating practices.

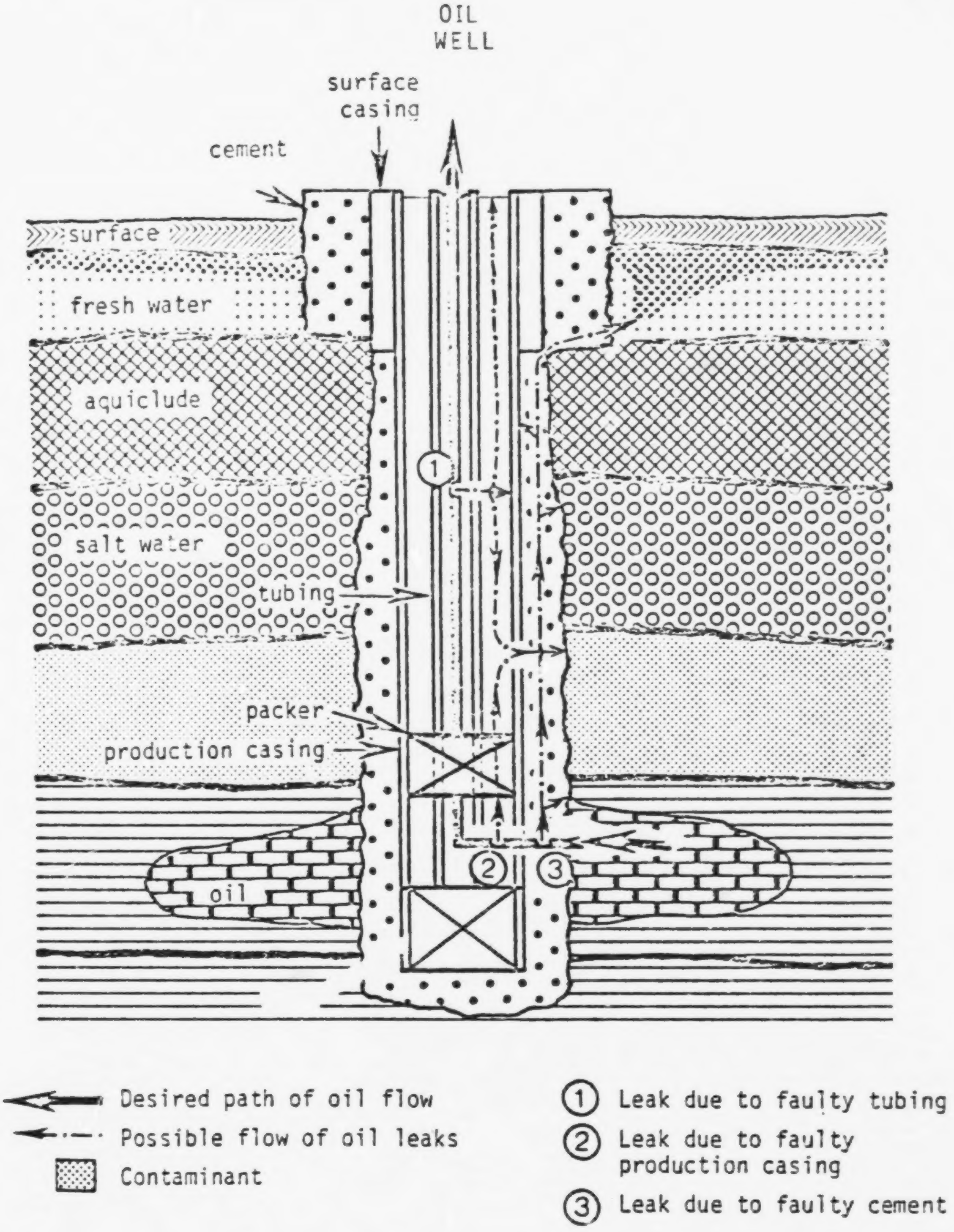
OIL
WELL
surface casing
cement
surface
fresh water
aquiclude
salt water
tubing
packer
production casing
oil
①
②
③
Desired path of oil flow
Possible flow of oil leaks
Contaminant
① Leak due to faulty tubing
② Leak due to faulty production casing
③ Leak due to faulty cement

Figure IV-10. Diagram of an oil well showing the potential paths of freshwater contamination resulting from well failure.

## TABLE IV-36

## LEVELS OF ONSHORE OIL PRODUCTION AND PERCENT OF TOTAL WATER SUPPLY DERIVED FROM GROUNDWATER SOURCES

| STATE | 1975 PRODUCTION[1] ($10^6$ bbl) | GROUNDWATER USE[2] GROUND |
|---|---|---|
| Alabama | 13.5 | 4 |
| Alaska | 9.5 | -- |
| Arkansas | 16.1 | 50 |
| California | 243.1 | 38 |
| Colorado | 38.1 | 16 |
| Florida | 41.9 | 20 |
| Illinois | 26.1 | 7 |
| Indiana | 4.6 | 5 |
| Kansas | 59.1 | 83 |
| Kentucky | 7.6 | 4 |
| Louisiana | 289.8 | 17 |
| Michigan | 24.4 | 7 |
| Mississippi | 46.6 | 37 |
| Montana | 32.8 | 2 |
| Nebraska | 6.1 | 55 |
| New Mexico | 95.1 | 50 |
| North Dakota | 20.5 | 14 |
| Ohio | 9.6 | 5 |
| Oklahoma | 163.1 | 59 |
| Pennsylvania | 3.3 | 4 |
| Texas | 1,221.2 | 34 |
| Utah | 42.3 | 16 |
| West Virginia | 2.5 | 1 |
| Wyoming | 135.9 | 4 |

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[1] U.S. Dept. of Int., Bureau of Mines, Quantity and Value of Crude Petroleum Produced and Approximate Number of Producing Oil Wells in the U.S.: 1975 and 1974.

[2] Water Atlas of the United States, Plate 32.

## E. Air Quality Impacts of Compression and Pumping Engines

Reference has been made throughout this report to the necessity of using either electric, natural gas, or diesel power plants to energize typical lifting pumps and compressors. The compressors are used for the injection of either a gaseous or liquid substance into the well formation to enhance recovery, while the lifting pumps are those required to move produced oil to the surface. This section of the report addresses the air quality implications of the use of these engines with respect to short term near-field impacts.

Lifting pumps are used, more or less in proportion to the amount of oil produced independent of the production method used. Thus, the ultimate impact of any of the separate pricing strategies is, essentially, proportional to the expected total output. Anticipating the production consequences described below in Chapter VI, little difference among all of the alternatives would be expected. The range in production from the lowest scenario to the highest is only about 2.5 percent. All pricing scenarios would, however, increase the impact from this source by about 9 percent relative to the Base Case.

Injection requirements depend on the specific technology. In-situ combustion and $CO_2$ injection require large gas compressors relative to the pumping needs of other technologies. Both of these techniques are expected to increase substantially if either of the third tier options promoting tertiary production are adopted (options IIIA or IIIB).

Electric motors utilizing externally produced electricity present no local air quality problems of any note. The use of these engines may have a minor secondary impact on the region as a whole due to the increased power demands they place on the regional power generating plants.

Emission rates for diesel- and natural gas-fired stationary engines are listed in Table IV-37. These values are taken from the EPA report AP-42, and represent an average of typical engines in use as stationary industrial power plants. Information on the fraction of total hydrocarbon emissions attributable to methane is as noted for gas engines but was not available for diesel engines.

Engine sizes vary between 20 and 1,000 horsepower. The typical walking beam production pump carries a 20 to 25 horsepower engine, and runs on electricity where it is available. Water injection pumps tend to be sized in the neighborhood of 100 gallons per minute at up to 3,000 psi, and this requires an engine of about 160 horsepower. Some larger systems that do a great deal of water processing tend to use several 1,000 hp gas-fired engines of either the turbine or reciprocating variety. Pressurized water in these systems is dispatched to injection wells by high pressure piping. Gaseous injection projects also tend to use large horsepower gas or electric compressor engines. Utilized horsepower ranges from 400 to 1,200 hp, with 1,000 hp units predominating.

TABLE IV-37

EMISSIONS LEVELS FOR DIESEL AND NATURAL GAS-DRIVEN COMPRESSOR ENGINES

| ($10^{-4}$ g/hp-sec) | DIESEL ($\leq$ 600 hp) | GAS (Turbine) | GAS (Reciprocal) |
|---|---|---|---|
| $SO_2$ | 2.59 | 0.006 | 0.006 |
| PM | 2.78 | - | - |
| $NO_x$ | 38.9 | 3.61[1] | 30.6[1] |
| HC | 3.11 | 0.278[2] | 12.2[2] |
| CO | 8.42 | 1.39 | 3.89 |

[1] Total $NO_x$ reported as $NO_2$.

[2] Total hydrocarbons, as C; between 90 and 95 percent is $CH_4$.

Source: U.S. Environmental Protection Agency, Compilation of Air Pollutant Emission Factors, Report No. AP-42, April 1973 (plus supplements 1-6).

A calculation of annual average concentration of $NO_x$ has been performed by the Austin branch of the Texas Air Control Board to assess the nitrogen dioxide levels surrounding a particularly large installation of gas-fired reciprocating compressor engines.[1] It was estimated that the 40 1,000-hp engines at that site would account for an annual $NO_2$ concentration of over 200 μg/$m^3$, twice the standard. Such a large collection of these engines could represent a significant long-term impact. Isolated units may need close scrutiny only in regions of documented sensitivity to additional annual $NO_2$ levels. Short-term impacts should be carefully evaluated in regions experiencing oxidant problems, since both nitrogen oxides and reactive hydrocarbons may be present in ample proportion.

Estimates of worst case concentrations of $SO_2$, $NO_x$, CO, and hydrocarbons were made according to the Workbook method described above.[2] High short-term concentrations might be expected in the vicinity of the sources, due to the limited height of stacks associated with compressors and engines.

There is no short-term National Ambient Air Quality Standard for $NO_x$. California has, however, a 1-hour standard for this pollutant, set at 470 μg/$m^3$. Worst case estimates indicate that this standard would be exceeded beyond the fence line for engines larger than about 200 horsepower. This potential problem could inhibit expansion of in-situ combustion projects, many of which would be situated in California.

Hydrocarbon emissions could lead to violations of the Federal 3-hour standard (160 μg/$m^3$) for the larger engine sizes (600 hp and larger), particularly if the engines were clustered. The worst case estimates for a single 600 hp engine showed a marginal likelihood of standard violation. A more serious constraint on project expansion or development could be restrictions on hydrocarbon emissions in oxidant non-attainment areas. Much of California and the Gulf Coast oil fields lie in such areas. It is not apparent currently if oilfield engines, even if aggregated over a large project, will be regulated as a result of non-attainment.

CO and $SO_2$ do not appear to pose any problems connected with oilfield engines and compressors.

Nitrogen dioxide is primarily known as an important precursor in the formation of photochemical smog. Photochemical reactions involving nitrogen oxides and other oxidants such as ozone can trigger a chain of chemical events which result in the oxidation of atmospheric hydrocarbons to highly toxic and irritating aldehydes and ketones. The participation of nitrogen oxides in the formation of photochemical smog is discussed in a number of texts.[3]

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[1] Personal communication, Texas Air Control Board, Austin, Austin, Texas, 1976.

[2] D.B. Turner, Workbook of Atmospheric Dispersion Estimates for the U.S. Environmental Protection Agency, 1970, pp. 11-17.

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[3] S.J. Williamson, Fundamentals of Air Pollution (Reading, Mass.: Addison-Wesley Publishing Co., 1973).

## F. Land Use Impacts

The major land use impact of oil production is the temporary restriction of land from other uses due to its occupation by production equipment, machinery, and roads. So many parameters influence the amount of land required for recovery from a specific field that it is difficult to quantify land use in a generalized fashion. Some general conclusions can be drawn, however.

The amount of surface area necessary for oil recovery operations is proportional to the amount of equipment used in the recovery. More equipment and, thus, more land is generally necessary for secondary and tertiary methods than for primary methods, although the need for associated gas processing equipment at a primary recovery project could alter this situation in many instances. However, in general other factors than stage of recovery are more important in determining land requirements, especially well density and formation characteristics.

Assuming that land requirements are greater for secondary and tertiary methods, the two third-stage options emphasizing tertiary production (IIIA and IIIB) could produce a greater impact on land use. Even in these cases the differences are not expected to be large.

Recovery projects do not occupy large amounts of land. Small plots of land surface above reservoirs are restricted from other use because they contain wells and associated equipment. These plots are fenced as needed to prevent intrusion by herded animals. Some land is also used by access roads. All of the rest of the land above the reservoir is usable. The surface is largely undisturbed and can be used for grazing and crop farming.

Furthermore, the restriction of the land is temporary. Once the reservoir has been exhausted the wells are plugged, and the equipment is removed. Land which was occupied can then be returned to its original use. The duration of occupation varies widely, depending on production characteristics of the reservoir. Secondary and tertiary projects enable oil recovery from fields which are unable to produce further by primary methods, and thus lengthen the functional life of the reservoirs and limit the use of the land for a longer period of time.

# CHAPTER V

## DESCRIPTION OF THE ENVIRONMENT

The intent of the proposed regulatory program is, as described in the preceding chapters, to achieve optimum domestic crude oil production. The main thrust of the several alternative pricing scenarios considered would be to change the geographic distribution of current production levels, generally increasing them everywhere. Little or no production from frontier areas other than those already categorized as reserves would be expected. Thus the major environmental impacts that would arise from changes in production levels would occur in the shaded regions in Figure V-1, a map showing the general location of domestic reserves.

It is immediately evident that these areas appear in parts of the United States with widely diverse environmental character. It is also apparent that the general scale of the impacted areas is much too large to support a highly localized discussion of existing environmental features. As a practical approach consistent with the emphasis given to the discussion of local (Chapter IV) and aggregated (Chapter VII) impacts, an appendix has been prepared (Appendix J) describing important environmental features of each Petroleum Demand Region and of specific locations which might be most affected by the pricing regulations. The specific locations include two coastal locations (Gulf of Mexico and California) and inland areas in Texas, Southern California, Louisiana, Wyoming, and Oklahoma.

The national and regional overview portions of the appendix consider air quality, water supply and usage, water quality, major biomes and land use, and socioeconomic factors. The local or subregional descriptions include physiographic, oceanographic and climatic data, resources, and environmental quality data.

The discussion of air quality focuses on potential constraints posed by the current or projected levels of ambient pollutant concentrations. Where current levels exceed the National Ambient Air Quality Standards, those regions are designated as non-attainment regions. Similarly, regions in which pollutant concentrations are expected to exceed standards through future growth are designated as Air Quality Maintenance Areas. Finally, in accordance with a court-upheld opinion of the intent of the Clean Air Act

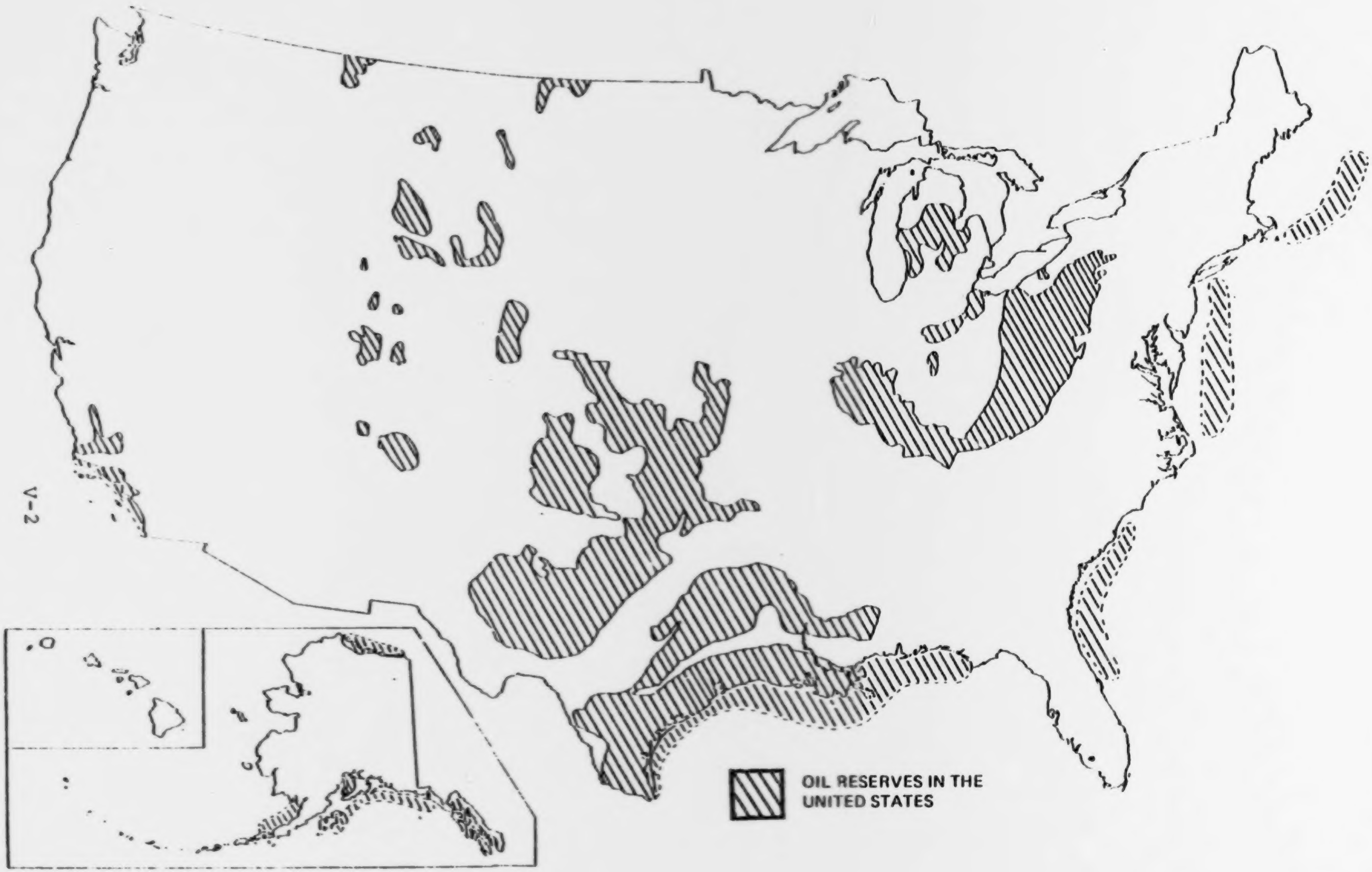
▨ OIL RESERVES IN THE UNITED STATES

Figure V-1. Oil reserves in the United States.

Amendments of 1970, future pollution increases in certain regions of the country will be limited to such changes in ambient levels as prevent significant deterioration of air quality.

All of these statutory requirements are being translated into policies and regulations affecting the growth of new sources of emissions. The process is still evolutionary but in any case will place some constraints on growth. That these constraints will affect petroleum production and processing is, however, clear even now. A permit to build a new storage facility in Southern California to accommodate shipments of Alaskan crude was denied on the basis that no additional hydrocarbon emissions could be tolerated in an oxidants non-attainment region.

The next aspect discussed, water supply and usage, is important more from a resources commitment viewpoint than from an environmental pollution viewpoint. Water is an essential element in production by secondary and several tertiary recovery methods. Considerations of availability are important particularly in arid or semi-arid parts of the United States. Restrictions on reinjection and underground disposal may also constrain future development.

Appendix J contains a broader discussion of these subjects, together with a series of maps, figures and tables summarizing a number of environmental factors.

# CHAPTER VI

# ENERGY IMPACTS OF ALTERNATIVE PRICING SCENARIOS

## A. Production Impacts

For each production scenario defined in Chapter II, the volumes of crude oil production in 1979 and 1985 in each Petroleum Supply Region (Figure VI-1) by type of technology employed were derived using the methodology described in Chapter III. The values shown were derived for use as input to the environmental impact analysis. The introduction to Chapter III explains in detail why the inter-case differences shown below are significantly greater than would be expected in actual practice. (In essence, the production estimates were based on pessimistic price expectations.)

Table VI-1 indicates the shorthand used hereafter to describe scenarios. For example, the description, "Alternative IIB with IIID" abbreviated IIB, IIID indicates a Stage II policy of holding the lower tier at constant real price and a Stage III policy of reducing the California gravity/price schedule.

Overall production volume impact analyses for the alternatives are presented in Tables VI-3 to VI-18. Table VI-2 shows 1975 volumes for comparison and Table VI-19 shows forecast volumes for 1985. The results are summarized in Table VI-20.

Perusal of Table VI-20 leads to three principal observations:

1. Production in 1979 under any of the pricing options is 6.5 to 9.5 percent greater than with Base Case prices.
2. Production differences among the cases are small: the best case (IIC, IIIA, C, D) is only 2.8 percent better than the worst case (IIC).
3. Even with the pessimistic set of price expectations assumed, an option exists (IIC, IIIA, C, D) that would bring forth production in 1979 at 99.9 percent of the rate that would be expected if crude oil price controls had lapsed in mid-1976.

The composite case consists of three price incentive elements -- allowing tertiary production to be sold at the free market price, redefining offshore wells with less than 40 barrels per day production from lower tier to stripper, reducing the price/gravity schedule for low gravity California crude oils -- plus permitting the real price of lower tier oil to decline (by holding the nominal price constant).

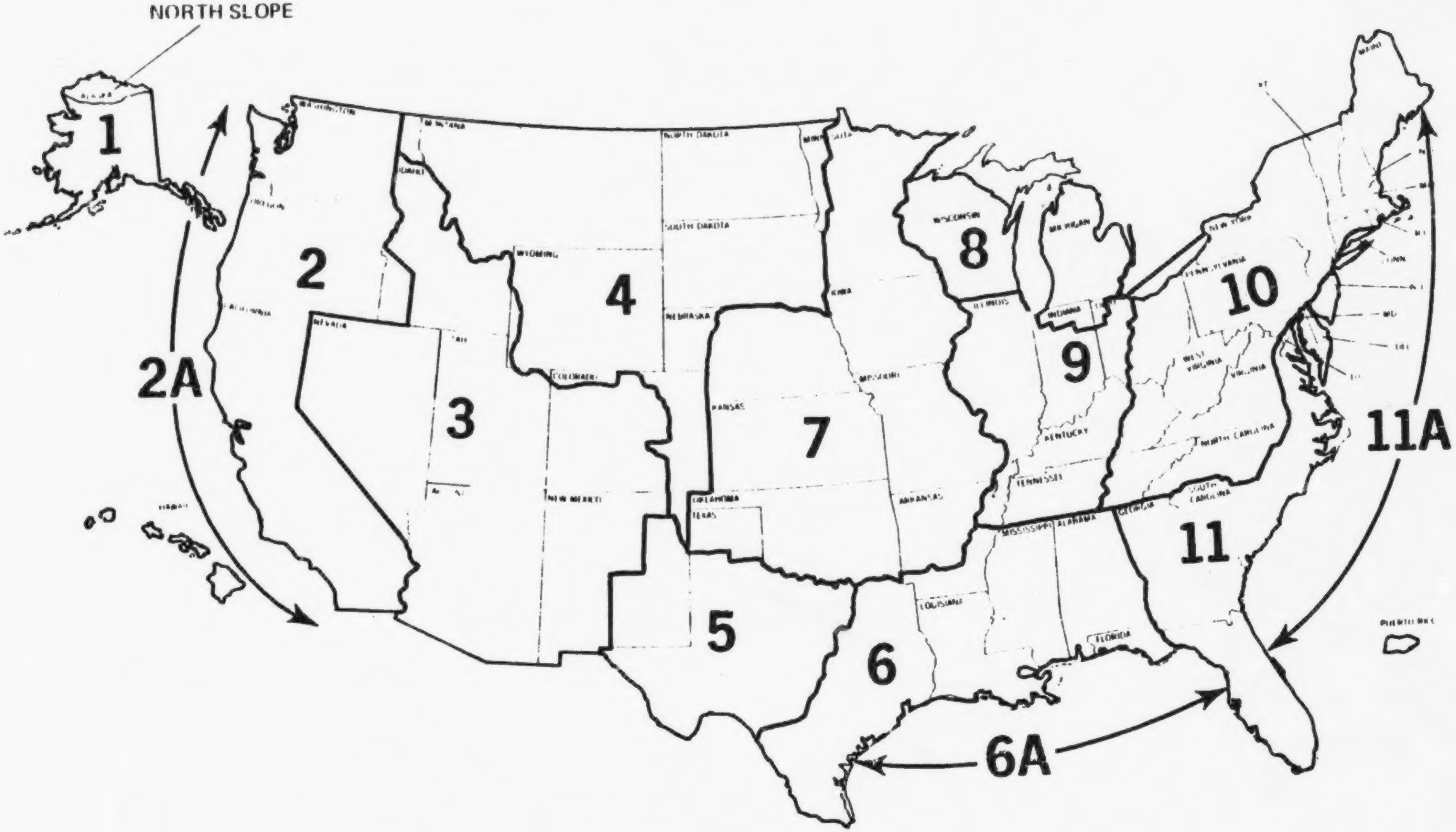
NORTH SLOPE
1
2
2A
3
4
5
6
6A
7
8
9
10
11
11A

Figure VI-1. Petroleum Provinces of the United States.

## TABLE VI-1

## SHORTHAND FOR PRICING ALTERNATIVES

| SHORTHAND | | PRICING POLICY DESCRIPTION |
|---|---|---|
| Base Case | Base Case -- | Lower tier held at $5.15 average nominal price (through May 1979); upper tier price adjusted to give $7.66 composite. |
| Stage II | Stage II -- | Composite price escalates 10 percent per year. |
| IIA | A | Same relative price increase for both tiers. |
| IIB | B | Lower tier held at constant average real price. |
| IIC | C | Lower tier held at constant average nominal price. |
| Stage III | Stage III -- | Additional incentive for special situations (composite can increase more than 10 percent per year to accommodate these). |
| IIIA | A | Tertiary production gets free market price. |
| IIIB | B | Total production from tertiary projects gets free market price. |
| IIIC | C | Redefine "strippers" to include deep onshore, plus offshore, wells. |
| IIID | D | Reduce California gravity schedule. |
| Decontrol (in 1976) | Self-explanatory | |

# TABLE VI-2

## OIL PRODUCTION BY NPC REGION FOR 1975 (THOUSAND BARRELS PER DAY)

| PRODUCTION CATEGORY / NPC REGION | CONVENTIONAL | STEAM INJECTION | IN SITU | $CO_2$/MISCIBLE | MICELLAR-POLYMER | CAUSTIC FLOODING | TOTAL |
|---|---|---|---|---|---|---|---|
| North Slope | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 1 | 190 | 0 | 0 | 0 | 0 | 0 | 190 |
| 2 | 490 | 180 | 0 | 0 | 0 | 0 | 670 |
| 2A | 220 | 0 | 0 | 0 | 0 | 0 | 220 |
| 3 | 140 | 0 | 0 | 0 | 0 | 0 | 140 |
| 4 | 620 | 0 | 0 | 0 | 0 | 0 | 620 |
| 5 | 2,000 | 0 | 0 | 50 | 0 | 0 | 2,050 |
| 6 | 2,405 | 0 | 5 | 30 | 0 | 0 | 2,440 |
| 6A | 990 | 0 | 0 | 0 | 0 | 0 | 990 |
| 7 | 730 | 0 | 0 | 0 | 0 | 0 | 730 |
| 8-9-10 | 220 | 0 | 0 | 0 | 0 | 0 | 220 |
| 11 | 110 | 0 | 0 | 0 | 0 | 0 | 110 |
| 11A | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| National | 8,115 | 180 | 5 | 80 | 0 | 0 | 8,380 |

## TABLE VI-3

## OIL PRODUCTION BY NPC REGION FOR BASE CASE IN 1979 (THOUSAND BARRELS PER DAY)

| PRODUCTION CATEGORY / NPC REGION | CONVENTIONAL | STEAM INJECTION | IN SITU | $CO_2$/MISCIBLE | MICELLAR-POLYMER | CAUSTIC FLOODING | TOTAL |
|---|---|---|---|---|---|---|---|
| North Slope | 1,420 | 0 | 0 | 0 | 0 | 0 | 1,420 |
| 1 | 120 | 0 | 0 | 0 | 0 | 0 | 120 |
| 2 | 820 | 170 | 0 | 0 | 0 | 0 | 990 |
| 2A | 90 | 0 | 0 | 0 | 0 | 0 | 90 |
| 3 | 180 | 0 | 0 | 0 | 0 | 0 | 180 |
| 4 | 470 | 0 | 0 | 0 | 0 | 0 | 470 |
| 5 | 1,640 | 0 | 0 | 20 | 0 | 0 | 1,660 |
| 6 | 2,610 | 0 | 10 | 10 | 0 | 0 | 2,630 |
| 6A | 1,350 | 0 | 0 | 0 | 0 | 0 | 1,350 |
| 7 | 520 | 0 | 0 | 0 | 0 | 0 | 520 |
| 8-9-10 | 160 | 0 | 0 | 0 | 0 | 0 | 160 |
| 11 | 100 | 0 | 0 | 0 | 0 | 0 | 100 |
| 11A | 60 | 0 | 0 | 0 | 0 | 0 | 60 |
| National | 9,540 | 170 | 10 | 30 | 0 | 0 | 9,750 |

## TABLE VI-4

## OIL PRODUCTION BY NPC REGION FOR ALTERNATIVE II.A ONLY IN 1979 (THOUSAND BARRELS PER DAY)

| PRODUCTION CATEGORY<br>NPC REGION | CONVENTIONAL | STEAM INJECTION | IN SITU | $CO_2$/MISCIBLE | MICELLAR-POLYMER | CAUSTIC FLOODING | TOTAL |
|---|---|---|---|---|---|---|---|
| North Slope | 1,420 | 0 | 0 | 0 | 0 | 0 | 1,420 |
| 1 | 120 | 0 | 0 | 0 | 0 | 0 | 120 |
| 2 | 850 | 170 | 20 | 10 | 0 | 0 | 1,050 |
| 2A | 160 | 0 | 0 | 0 | 0 | 0 | 160 |
| 3 | 180 | 0 | 0 | 0 | 0 | 0 | 180 |
| 4 | 540 | 0 | 0 | 0 | 0 | 0 | 540 |
| 5 | 1,640 | 0 | 0 | 50 | 0 | 0 | 1,690 |
| 6 | 2,930 | 0 | 20 | 30 | 0 | 0 | 2,980 |
| 6A | 1,390 | 0 | 0 | 0 | 0 | 0 | 1,390 |
| 7 | 560 | 0 | 0 | 0 | 0 | 0 | 560 |
| 8-9-10 | 210 | 0 | 0 | 0 | 0 | 0 | 210 |
| 11 | 100 | 0 | 0 | 0 | 0 | 0 | 100 |
| 11A | 60 | 0 | 0 | 0 | 0 | 0 | 60 |
| National | 10,160 | 170 | 40 | 90 | 0 | 0 | 10,460 |

## TABLE VI-5

## OIL PRODUCTION BY NPC REGION FOR ALTERNATIVE II.B ONLY IN 1979 (THOUSAND BARRELS PER DAY)

| PRODUCTION CATEGORY / NPC REGION | CONVENTIONAL | STEAM INJECTION | IN SITU | $CO_2$/MISCIBLE | MICELLAR-POLYMER | CAUSTIC FLOODING | TOTAL |
|---|---|---|---|---|---|---|---|
| North Slope | 1,420 | 0 | 0 | 0 | 0 | 0 | 1,420 |
| 1 | 120 | 0 | 0 | 0 | 0 | 0 | 120 |
| 2 | 850 | 180 | 20 | 10 | 0 | 0 | 1,060 |
| 2A | 160 | 0 | 0 | 0 | 0 | 0 | 160 |
| 3 | 180 | 0 | 0 | 0 | 0 | 0 | 180 |
| 4 | 540 | 0 | 0 | 0 | 0 | 0 | 540 |
| 5 | 1,640 | 0 | 0 | 50 | 0 | 0 | 1,690 |
| 6 | 2,930 | 0 | 20 | 30 | 0 | 0 | 2,980 |
| 6A | 1,390 | 0 | 0 | 0 | 0 | 0 | 1,390 |
| 7 | 560 | 0 | 0 | 0 | 0 | 0 | 560 |
| 8-9-10 | 210 | 0 | 0 | 0 | 0 | 0 | 210 |
| 11 | 100 | 0 | 0 | 0 | 0 | 0 | 100 |
| 11A | 60 | 0 | 0 | 0 | 0 | 0 | 60 |
| National | 10,160 | 180 | 40 | 90 | 0 | 0 | 10,470 |

TABLE VI-6

## OIL PRODUCTION BY NPC REGION FOR ALTERNATIVE II.C ONLY IN 1979 (THOUSAND BARRELS PER DAY)

| PRODUCTION CATEGORY / NPC REGION | CONVENTIONAL | STEAM INJECTION | IN SITU | $CO_2$/MISCIBLE | MICELLAR-POLYMER | CAUSTIC FLOODING | TOTAL |
|---|---|---|---|---|---|---|---|
| North Slope | 1,420 | 0 | 0 | 0 | 0 | 0 | 1,420 |
| 1 | 120 | 0 | 0 | 0 | 0 | 0 | 120 |
| 2 | 850 | 170 | 0 | 0 | 0 | 0 | 1,020 |
| 2A | 160 | 0 | 0 | 0 | 0 | 0 | 160 |
| 3 | 180 | 0 | 0 | 0 | 0 | 0 | 180 |
| 4 | 540 | 0 | 0 | 0 | 0 | 0 | 540 |
| 5 | 1,650 | 0 | 0 | 20 | 0 | 0 | 1,670 |
| 6 | 2,930 | 0 | 10 | 10 | 0 | 0 | 2,950 |
| 6A | 1,390 | 0 | 0 | 0 | 0 | 0 | 1,390 |
| 7 | 560 | 0 | 0 | 0 | 0 | 0 | 560 |
| 8-9-10 | 210 | 0 | 0 | 0 | 0 | 0 | 210 |
| 11 | 100 | 0 | 0 | 0 | 0 | 0 | 100 |
| 11A | 60 | 0 | 0 | 0 | 0 | 0 | 60 |
| National | 10,170 | 170 | 10 | 30 | 0 | 0 | 10,380 |

## TABLE VI-7

## OIL PRODUCTION BY NPC REGION FOR ALTERNATIVE II.A AND III.A IN 1979 (THOUSAND BARRELS PER DAY)

| PRODUCTION CATEGORY / NPC REGION | CONVENTIONAL | STEAM INJECTION | IN SITU | $CO_2$/MISCIBLE | MICELLAR-POLYMER | CAUSTIC FLOODING | TOTAL |
|---|---|---|---|---|---|---|---|
| North Slope | 1,420 | 0 | 0 | 0 | 0 | 0 | 1,420 |
| 1 | 120 | 0 | 0 | 0 | 0 | 0 | 120 |
| 2 | 850 | 210 | 30 | 20 | 0 | 0 | 1,110 |
| 2A | 160 | 0 | 0 | 0 | 0 | 0 | 160 |
| 3 | 180 | 0 | 0 | 0 | 0 | 0 | 180 |
| 4 | 540 | 0 | 0 | 0 | 0 | 0 | 540 |
| 5 | 1,640 | 0 | 0 | 110 | 0 | 0 | 1,750 |
| 6 | 2,870 | 0 | 30 | 60 | 0 | 0 | 2,960 |
| 6A | 1,380 | 0 | 0 | 0 | 0 | 0 | 1,380 |
| 7 | 540 | 0 | 0 | 0 | 0 | 0 | 540 |
| 8-9-10 | 210 | 0 | 0 | 0 | 0 | 0 | 210 |
| 11 | 100 | 0 | 0 | 0 | 0 | 0 | 100 |
| 11A | 60 | 0 | 0 | 0 | 0 | 0 | 60 |
| National | 10,070 | 210 | 60 | 190 | 0 | 0 | 10,530 |

TABLE VI-8

## OIL PRODUCTION BY NPC REGION FOR ALTERNATIVE II.B AND III.A IN 1979 (THOUSAND BARRELS PER DAY)

| PRODUCTION CATEGORY / NPC REGION | CONVENTIONAL | STEAM INJECTION | IN SITU | $CO_2$/MISCIBLE | MICELLAR-POLYMER | CAUSTIC FLOODING | TOTAL |
|---|---|---|---|---|---|---|---|
| North Slope | 1,420 | 0 | 0 | 0 | 0 | 0 | 1,420 |
| 1 | 120 | 0 | 0 | 0 | 0 | 0 | 120 |
| 2 | 850 | 210 | 30 | 20 | 0 | 0 | 1,110 |
| 2A | 160 | 0 | 0 | 0 | 0 | 0 | 160 |
| 3 | 180 | 0 | 0 | 0 | 0 | 0 | 180 |
| 4 | 540 | 0 | 0 | 0 | 0 | 0 | 540 |
| 5 | 1,640 | 0 | 0 | 110 | 0 | 0 | 1,750 |
| 6 | 2,820 | 0 | 30 | 60 | 0 | 0 | 2,910 |
| 6A | 1,380 | 0 | 0 | 0 | 0 | 0 | 1,380 |
| 7 | 530 | 0 | 0 | 0 | 0 | 0 | 530 |
| 8-9-10 | 210 | 0 | 0 | 0 | 0 | 0 | 210 |
| 11 | 100 | 0 | 0 | 0 | 0 | 0 | 100 |
| 11A | 60 | 0 | 0 | 0 | 0 | 0 | 60 |
| National | 10,010 | 210 | 60 | 190 | 0 | 0 | 10,470 |

## TABLE VI-9

## OIL PRODUCTION BY NPC REGION FOR ALTERNATIVE II.C AND III.A IN 1979 (THOUSAND BARRELS PER DAY)

| PRODUCTION CATEGORY / NPC REGION | CONVENTIONAL | STEAM INJECTION | IN SITU | $CO_2$/MISCIBLE | MICELLAR-POLYMER | CAUSTIC FLOODING | TOTAL |
|---|---|---|---|---|---|---|---|
| North Slope | 1,420 | 0 | 0 | 0 | 0 | 0 | 1,420 |
| 1 | 120 | 0 | 0 | 0 | 0 | 0 | 120 |
| 2 | 850 | 210 | 30 | 20 | 0 | 0 | 1,110 |
| 2A | 160 | 0 | 0 | 0 | 0 | 0 | 160 |
| 3 | 180 | 0 | 0 | 0 | 0 | 0 | 180 |
| 4 | 540 | 0 | 0 | 0 | 0 | 0 | 540 |
| 5 | 1,640 | 0 | 0 | 110 | 0 | 0 | 1,750 |
| 6 | 2,940 | 0 | 30 | 60 | 0 | 0 | 3,030 |
| 6A | 1,390 | 0 | 0 | 0 | 0 | 0 | 1,390 |
| 7 | 560 | 0 | 0 | 0 | 0 | 0 | 560 |
| 8-9-10 | 210 | 0 | 0 | 0 | 0 | 0 | 210 |
| 11 | 100 | 0 | 0 | 0 | 0 | 0 | 100 |
| 11A | 60 | 0 | 0 | 0 | 0 | 0 | 60 |
| National | 10,170 | 210 | 60 | 190 | 0 | 0 | 10,630 |

TABLE VI-10

## OIL PRODUCTION BY NPC REGION FOR ALTERNATIVE II.A AND III.B IN 1979 (THOUSAND BARRELS PER DAY)

| PRODUCTION CATEGORY / NPC REGION | CONVENTIONAL | STEAM INJECTION | IN SITU | $CO_2$/MISCIBLE | MICELLAR-POLYMER | CAUSTIC FLOODING | TOTAL |
|---|---|---|---|---|---|---|---|
| North Slope | 1,420 | 0 | 0 | 0 | 0 | 0 | 1,420 |
| 1 | 120 | 0 | 0 | 0 | 0 | 0 | 120 |
| 2 | 850 | 210 | 30 | 30 | 0 | 0 | 1,120 |
| 2A | 160 | 0 | 0 | 0 | 0 | 0 | 160 |
| 3 | 180 | 0 | 0 | 0 | 0 | 0 | 180 |
| 4 | 540 | 0 | 0 | 0 | 0 | 0 | 540 |
| 5 | 1,640 | 0 | 0 | 140 | 0 | 0 | 1,780 |
| 6 | 2,780 | 0 | 30 | 80 | 0 | 0 | 2,890 |
| 6A | 1,370 | 0 | 0 | 0 | 0 | 0 | 1,370 |
| 7 | 520 | 0 | 0 | 0 | 0 | 0 | 520 |
| 8-9-10 | 210 | 0 | 0 | 0 | 0 | 0 | 210 |
| 11 | 100 | 0 | 0 | 0 | 0 | 0 | 100 |
| 11A | 60 | 0 | 0 | 0 | 0 | 0 | 60 |
| National | 9,950 | 210 | 60 | 250 | 0 | 0 | 10,470 |

## TABLE VI-11

## OIL PRODUCTION BY NPC REGION FOR ALTERNATIVE II.B AND III.B IN 1979 (THOUSAND BARRELS PER DAY)

| PRODUCTION CATEGORY / NPC REGION | CONVENTIONAL | STEAM INJECTION | IN SITU | $CO_2$/MISCIBLE | MICELLAR-POLYMER | CAUSTIC FLOODING | TOTAL |
|---|---|---|---|---|---|---|---|
| North Slope | 1,420 | 0 | 0 | 0 | 0 | 0 | 1,420 |
| 1 | 120 | 0 | 0 | 0 | 0 | 0 | 120 |
| 2 | 850 | 210 | 30 | 30 | 0 | 0 | 1,120 |
| 2A | 160 | 0 | 0 | 0 | 0 | 0 | 160 |
| 3 | 180 | 0 | 0 | 0 | 0 | 0 | 180 |
| 4 | 540 | 0 | 0 | 0 | 0 | 0 | 540 |
| 5 | 1,640 | 0 | 0 | 140 | 0 | 0 | 1,780 |
| 6 | 2,720 | 0 | 30 | 80 | 0 | 0 | 2,830 |
| 6A | 1,360 | 0 | 0 | 0 | 0 | 0 | 1,360 |
| 7 | 560 | 0 | 0 | 0 | 0 | 0 | 560 |
| 8-9-10 | 210 | 0 | 0 | 0 | 0 | 0 | 210 |
| 11 | 100 | 0 | 0 | 0 | 0 | 0 | 100 |
| 11A | 60 | 0 | 0 | 0 | 0 | 0 | 60 |
| National | 9,880 | 210 | 60 | 250 | 0 | 0 | 10,400 |

## TABLE VI-12

### OIL PRODUCTION BY NPC REGION FOR ALTERNATIVE II.C AND III.B IN 1979 (THOUSAND BARRELS PER DAY)

| PRODUCTION CATEGORY / NPC REGION | CONVENTIONAL | STEAM INJECTION | IN SITU | $CO_2$/MISCIBLE | MICELLAR-POLYMER | CAUSTIC FLOODING | TOTAL |
|---|---|---|---|---|---|---|---|
| North Slope | 1,420 | 0 | 0 | 0 | 0 | 0 | 1,420 |
| 1 | 120 | 0 | 0 | 0 | 0 | 0 | 120 |
| 2 | 850 | 210 | 30 | 30 | 0 | 0 | 1,120 |
| 2A | 160 | 0 | 0 | 0 | 0 | 0 | 160 |
| 3 | 180 | 0 | 0 | 0 | 0 | 0 | 180 |
| 4 | 540 | 0 | 0 | 0 | 0 | 0 | 540 |
| 5 | 1,640 | 0 | 0 | 140 | 0 | 0 | 1,780 |
| 6 | 2,860 | 0 | 30 | 80 | 0 | 0 | 2,970 |
| 6A | 1,380 | 0 | 0 | 0 | 0 | 0 | 1,380 |
| 7 | 540 | 0 | 0 | 0 | 0 | 0 | 540 |
| 8-9-10 | 210 | 0 | 0 | 0 | 0 | 0 | 210 |
| 11 | 100 | 0 | 0 | 0 | 0 | 0 | 100 |
| 11A | 60 | 0 | 0 | 0 | 0 | 0 | 60 |
| National | 10,060 | 210 | 60 | 250 | 0 | 0 | 10,580 |

## TABLE VI-13

## OIL PRODUCTION BY NPC REGION FOR ALTERNATIVE II.A AND III.C IN 1979 (THOUSAND BARRELS PER DAY)

| PRODUCTION CATEGORY / NPC REGION | CONVENTIONAL | STEAM INJECTION | IN SITU | $CO_2$/MISCIBLE | MICELLAR-POLYMER | CAUSTIC FLOODING | TOTAL |
|---|---|---|---|---|---|---|---|
| North Slope | 1,420 | 0 | 0 | 0 | 0 | 0 | 1,420 |
| 1 | 120 | 0 | 0 | 0 | 0 | 0 | 120 |
| 2 | 850 | 170 | 20 | 10 | 0 | 0 | 1,050 |
| 2A | 160 | 0 | 0 | 0 | 0 | 0 | 160 |
| 3 | 180 | 0 | 0 | 0 | 0 | 0 | 180 |
| 4 | 540 | 0 | 0 | 0 | 0 | 0 | 540 |
| 5 | 1,640 | 0 | 0 | 50 | 0 | 0 | 1,690 |
| 6 | 2,930 | 0 | 20 | 30 | 0 | 0 | 2,980 |
| 6A | 1,420 | 0 | 0 | 0 | 0 | 0 | 1,420 |
| 7 | 560 | 0 | 0 | 0 | 0 | 0 | 560 |
| 8-9-10 | 210 | 0 | 0 | 0 | 0 | 0 | 210 |
| 11 | 100 | 0 | 0 | 0 | 0 | 0 | 100 |
| 11A | 60 | 0 | 0 | 0 | 0 | 0 | 60 |
| National | 10,190 | 170 | 40 | 90 | 0 | 0 | 10,490 |

## TABLE VI-14

## OIL PRODUCTION BY NPC REGION FOR ALTERNATIVE II.B AND III.C IN 1979 (THOUSAND BARRELS PER DAY)

| PRODUCTION CATEGORY / NPC REGION | CONVENTIONAL | STEAM INJECTION | IN SITU | $CO_2$/MISCIBLE | MICELLAR-POLYMER | CAUSTIC FLOODING | TOTAL |
|---|---|---|---|---|---|---|---|
| North Slope | 1,420 | 0 | 0 | 0 | 0 | 0 | 1,420 |
| 1 | 120 | 0 | 0 | 0 | 0 | 0 | 120 |
| 2 | 850 | 180 | 20 | 10 | 0 | 0 | 1,060 |
| 2A | 160 | 0 | 0 | 0 | 0 | 0 | 160 |
| 3 | 180 | 0 | 0 | 0 | 0 | 0 | 180 |
| 4 | 540 | 0 | 0 | 0 | 0 | 0 | 540 |
| 5 | 1,640 | 0 | 0 | 50 | 0 | 0 | 1,690 |
| 6 | 2,930 | 0 | 20 | 30 | 0 | 0 | 2,980 |
| 6A | 1,420 | 0 | 0 | 0 | 0 | 0 | 1,420 |
| 7 | 560 | 0 | 0 | 0 | 0 | 0 | 560 |
| 8-9-10 | 210 | 0 | 0 | 0 | 0 | 0 | 210 |
| 11 | 100 | 0 | 0 | 0 | 0 | 0 | 100 |
| 11A | 60 | 0 | 0 | 0 | 0 | 0 | 60 |
| National | 10,190 | 180 | 40 | 90 | 0 | 0 | 10,500 |

TABLE VI-15

OIL PRODUCTION BY NPC REGION
FOR ALTERNATIVE II.C AND III.C
IN 1979 (THOUSAND BARRELS PER DAY)

| PRODUCTION CATEGORY / NPC REGION | CONVENTIONAL | STEAM INJECTION | IN SITU | $CO_2$/MISCIBLE | MICELLAR-POLYMER | CAUSTIC FLOODING | TOTAL |
|---|---|---|---|---|---|---|---|
| North Slope | 1,420 | 0 | 0 | 0 | 0 | 0 | 1,420 |
| 1 | 120 | 0 | 0 | 0 | 0 | 0 | 120 |
| 2 | 850 | 170 | 0 | 0 | 0 | 0 | 1,020 |
| 2A | 160 | 0 | 0 | 0 | 0 | 0 | 160 |
| 3 | 180 | 0 | 0 | 0 | 0 | 0 | 180 |
| 4 | 540 | 0 | 0 | 0 | 0 | 0 | 540 |
| 5 | 1,640 | 0 | 0 | 20 | 0 | 0 | 1,670 |
| 6 | 2,930 | 0 | 10 | 10 | 0 | 0 | 2,950 |
| 6A | 1,420 | 0 | 0 | 0 | 0 | 0 | 1,420 |
| 7 | 560 | 0 | 0 | 0 | 0 | 0 | 560 |
| 8-9-10 | 210 | 0 | 0 | 0 | 0 | 0 | 210 |
| 11 | 100 | 0 | 0 | 0 | 0 | 0 | 100 |
| 11A | 60 | 0 | 0 | 0 | 0 | 0 | 60 |
| National | 10,200 | 170 | 10 | 30 | 0 | 0 | 10,410 |

TABLE VI-16

## OIL PRODUCTION BY NPC REGION FOR ALTERNATIVE II.A AND III.D IN 1979 (THOUSAND BARRELS PER DAY)

| PRODUCTION CATEGORY / NPC REGION | CONVENTIONAL | STEAM INJECTION | IN SITU | $CO_2$/MISCIBLE | MICELLAR-POLYMER | CAUSTIC FLOODING | TOTAL |
|---|---|---|---|---|---|---|---|
| North Slope | 1,420 | 0 | 0 | 0 | 0 | 0 | 1,420 |
| 1 | 120 | 0 | 0 | 0 | 0 | 0 | 120 |
| 2 | 870 | 170 | 20 | 10 | 0 | 0 | 1,070 |
| 2A | 160 | 0 | 0 | 0 | 0 | 0 | 160 |
| 3 | 180 | 0 | 0 | 0 | 0 | 0 | 180 |
| 4 | 540 | 0 | 0 | 0 | 0 | 0 | 540 |
| 5 | 1,640 | 0 | 0 | 50 | 0 | 0 | 1,690 |
| 6 | 2,930 | 0 | 20 | 30 | 0 | 0 | 2,980 |
| 6A | 1,390 | 0 | 0 | 0 | 0 | 0 | 1,390 |
| 7 | 560 | 0 | 0 | 0 | 0 | 0 | 560 |
| 8-9-10 | 210 | 0 | 0 | 0 | 0 | 0 | 210 |
| 11 | 100 | 0 | 0 | 0 | 0 | 0 | 100 |
| 11A | 60 | 0 | 0 | 0 | 0 | 0 | 60 |
| National | 10,180 | 170 | 40 | 90 | 0 | 0 | 10,480 |

TABLE VI-17

## OIL PRODUCTION BY NPC REGION FOR ALTERNATIVE II.B AND III.D IN 1979 (THOUSAND BARRELS PER DAY)

| PRODUCTION CATEGORY / NPC REGION | CONVENTIONAL | STEAM INJECTION | IN SITU | $CO_2$/MISCIBLE | MICELLAR-POLYMER | CAUSTIC FLOODING | TOTAL |
|---|---|---|---|---|---|---|---|
| North Slope | 1,420 | 0 | 0 | 0 | 0 | 0 | 1,420 |
| 1 | 120 | 0 | 0 | 0 | 0 | 0 | 120 |
| 2 | 870 | 180 | 20 | 10 | 0 | 0 | 1,080 |
| 2A | 160 | 0 | 0 | 0 | 0 | 0 | 160 |
| 3 | 180 | 0 | 0 | 0 | 0 | 0 | 180 |
| 4 | 540 | 0 | 0 | 0 | 0 | 0 | 540 |
| 5 | 1,640 | 0 | 0 | 50 | 0 | 0 | 1,690 |
| 6 | 2,930 | 0 | 20 | 30 | 0 | 0 | 2,980 |
| 6A | 1,390 | 0 | 0 | 0 | 0 | 0 | 1,390 |
| 7 | 560 | 0 | 0 | 0 | 0 | 0 | 560 |
| 8-9-10 | 210 | 0 | 0 | 0 | 0 | 0 | 210 |
| 11 | 100 | 0 | 0 | 0 | 0 | 0 | 100 |
| 11A | 60 | 0 | 0 | 0 | 0 | 0 | 60 |
| National | 10,180 | 160 | 40 | 90 | 0 | 0 | 10,490 |

TABLE VI-18

## OIL PRODUCTION BY NPC REGION FOR ALTERNATIVE II.C AND III.D IN 1979 (THOUSAND BARRELS PER DAY)

| PRODUCTION CATEGORY<br>NPC REGION | CONVENTIONAL | STEAM INJECTION | IN SITU | $CO_2$/MISCIBLE | MICELLAR-POLYMER | CAUSTIC FLOODING | TOTAL |
|---|---|---|---|---|---|---|---|
| North Slope | 1,420 | 0 | 0 | 0 | 0 | 0 | 1,420 |
| 1 | 120 | 0 | 0 | 0 | 0 | 0 | 120 |
| 2 | 870 | 170 | 0 | 0 | 0 | 0 | 1,040 |
| 2A | 160 | 0 | 0 | 0 | 0 | 0 | 160 |
| 3 | 180 | 0 | 0 | 0 | 0 | 0 | 180 |
| 4 | 540 | 0 | 0 | 0 | 0 | 0 | 540 |
| 5 | 1,640 | 0 | 0 | 20 | 0 | 0 | 1,670 |
| 6 | 2,930 | 0 | 10 | 10 | 0 | 0 | 2,950 |
| 6A | 1,390 | 0 | 0 | 0 | 0 | 0 | 1,390 |
| 7 | 560 | 0 | 0 | 0 | 0 | 0 | 560 |
| 8-9-10 | 210 | 0 | 0 | 0 | 0 | 0 | 210 |
| 11 | 100 | 0 | 0 | 0 | 0 | 0 | 100 |
| 11A | 60 | 0 | 0 | 0 | 0 | 0 | 60 |
| National | 10,190 | 170 | 10 | 30 | 0 | 0 | 10,400 |

## TABLE VI-19

## OIL PRODUCTION BY NPC REGION FOR ALL ALTERNATIVES IN 1985 (THOUSAND BARRELS PER DAY)

| PRODUCTION CATEGORY / NPC REGION | CONVENTIONAL | STEAM INJECTION | IN SITU | $CO_2$/MISCIBLE | MICELLAR-POLYMER | CAUSTIC FLOODING | TOTAL |
|---|---|---|---|---|---|---|---|
| North Slope | 2,050 | 0 | 0 | 0 | 0 | 0 | 2,050 |
| 1 | 330 | 0 | 0 | 0 | 0 | 0 | 330 |
| 2 | 1,120 | 580 | 100 | 40 | 0 | 0 | 1,840 |
| 2A | 640 | 0 | 0 | 0 | 0 | 0 | 640 |
| 3 | 140 | 0 | 0 | 0 | 0 | 0 | 140 |
| 4 | 510 | 0 | 0 | 10 | 30 | 0 | 550 |
| 5 | 1,170 | 0 | 0 | 160 | 0 | 0 | 1,330 |
| 6 | 2,710 | 10 | 70 | 80 | 0 | 0 | 2,870 |
| 6A | 1,420 | 0 | 0 | 0 | 0 | 0 | 1,420 |
| 7 | 430 | 0 | 10 | 0 | 40 | 0 | 480 |
| 8-9-10 | 280 | 0 | 0 | 0 | 20 | 0 | 300 |
| 11 | 120 | 0 | 0 | 0 | 0 | 0 | 120 |
| 11A | 140 | 0 | 0 | 0 | 0 | 0 | 140 |
| National | 11,060 | 590 | 180 | 290 | 90 | 0 | 12,210 |

TABLE VI-20

## DOMESTIC OIL PRODUCTION UNDER VARIOUS PRICING ALTERNATIVES, 1979 AND 1985

(Millions of Barrels Per Day)

| CRUDE PRICE OPTION | 1975 | 1979[1] | 1985[1] |
|---|---|---|---|
| Base Case | 8.38 | 9.75 | 12.21 |
| Stage IIA | -- | 10.46 | 12.21 |
| IIB | -- | 10.47 | 12.21 |
| IIC | -- | 10.38 | 12.21 |
| Stage IIA, IIIA | -- | 10.53 | 12.21 |
| IIB, IIIA | -- | 10.47 | 12.21 |
| IIC, IIIA | -- | 10.63 | 12.21 |
| IIA, IIIB | -- | 10.47 | 12.21 |
| IIB, IIIB | -- | 10.40 | 12.21 |
| IIC, IIIB | -- | 10.58 | 12.21 |
| IIA, IIIC | -- | 10.49 | 12.21 |
| IIB, IIIC | -- | 10.50 | 12.21 |
| IIC, IIIC | -- | 10.40 | 12.21 |
| IIA, IIID | -- | 10.48 | 12.21 |
| IIB, IIID | -- | 10.49 | 12.21 |
| IIC, IIID | -- | 10.40 | 12.21 |
| IIIA,C,D, IIC | -- | 10.67 | 12.21 |
| Decontrol (in 1976) | -- | 10.68 | 12.21 |

[1] Include 1.42 Alaskan North Slope and 0.20 NPR-1.

## B. Price Effects Upon Demand

This section will forecast the demand for products under the various price options with the use of an abstract of the Project Independence Evaluation Systems (PIES) model of energy demand.[1]

### 1. The PIES Model

The demand for petroleum products is expressed in the PIES model by

$$\log \left(\frac{q_i^d}{N}\right) = \alpha + \beta_i \log (P_i) + \gamma \log \left(\frac{Y}{N}\right) \qquad (1)$$

where $q_i^d$ is the volume demand for product i

$P_i$ is the price of product i

y is a measure of economic activity, either personal incomes or value added in manufacturing

N is the size of the population.

The model has been estimated for the four major products -- gasoline, kerosine and jet fuel, distillate and residual -- on a time-series basis, with breakdowns for the principal sectors of the economy and the nine Census Regions.[2] Some important constraints are imposed upon the parameters $\beta$ and $\gamma$, respectively the price and income elasticities of demand. The income elasticity of demand $\gamma$ is constrained to equality for all fuels in each sector. The effects of the prices of other fuels upon the demand for a specific product are constrained to zero. Finally, the published details do not permit any variation in the elasticities by region.

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[1] U.S. Federal Energy Administration, National Energy Outlook (1976), Appendix C.

[2] For the industrial sector, the demand and activity variables are measured in absolute, rather than per capita, values. In the transportation sector, the demand for gasoline is modelled in a multi-equation model, the reduced form of which is equivalent to (1). The demands for miscellaneous products are modelled separately, usually as simple trends.

For purposes of extrapolation, the demand model (1) yields the linear approximation

$$\frac{\Delta q_i^d}{q_i^d} \approx \beta_i\left(\frac{\Delta P_i}{P_i}\right) + \gamma\left(\frac{\Delta Y}{Y}\right) + (1-\gamma)\left(\frac{\Delta N}{N}\right) \qquad (2)$$

according to which the proportional change in demand for the product is expressed as a linear function of the proportional changes in prices, income (or output) and population, the coefficients in each case being the appropriate elasticities of demand.[3]

The values of the independent variables in 1979 and 1985 are derived from analysis of regulatory options in the case of prices and from the DRI predictions for personal incomes, manufacturing output and population.[4]

## 2. The Determination of Product Prices

Given the calculated alterations in the average price of the crude intake under the various policy options (see Chapter III), the resulting changes in product prices must be determined in order to be fed into the demand model.

An initial simplification is in order. The various Stage II and III alternative price policies will be shown to involve small differences in product prices (of the order of 0.4 percent or less) and even smaller differences in demand (less than 0.2 percent). Consequently, only two Stage II and III price policies, a low one and a high one, will be analyzed and compared to the Base Case and decontrol policies. The first of these involves an average domestic crude price of $8.77 in 1979 (in 1975 dollars); it represents the five low price options among the panoply of alternatives under Stages II and III.[5] The high price options involve a slightly (2.3 percent) higher average price for domestic crude in 1979 -- $8.97, again in constant 1975 dollars.[6]

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[3] The approximation neglects terms of the order of $(\Delta P/P)^2$, $(\Delta Y/Y)^2$, $(\Delta N/N)^2$ and above. For 1979 predictions, where all variables grow by a factor of 0.15 or less, no significant inaccuracy is involved.

[4] U.S. Federal Energy Administration, 1976 National Energy Outlook, pp. B-16, C-21, C-22.

Increases in the price of crude oil affect the prices of refined products in two ways. In the first place, the price at which refiners are willing to supply specific quantities of the product is raised. Then, to the extent that competitive factors are present on the sellers' side of these markets, the actual market price changes by a different proportion for different products, depending on the responsiveness of the demand for and the supply of that product to changes in its price as the market seeks a new equilibrium.

It will be assumed that gross margins in the stages of the oil industry downstream from the production of crude will change in the same proportion as the predicted changes in costs in these subsequent stages of the industry.[7] The shares of profits in the revenues of the transportation, refining, wholesale and retail sectors are assumed to remain constant at their 1965 levels, at least as far as initial supply prices are concerned.

The increases in the prices of the total crude intake at U.S. refineries and the ensuing expected increases in the supply prices of products at the wholesale and retail levels are reported in Table VI-21. The calculation of the average price of crude intake is based upon 1979 importation rates of 38.5 percent of crude requirements in the Base Case option and 34.0 and 34.5 percent in the two basic Stage II and III options. These values were arrived at by iteration

---

[5] The options represented are (IIA), (IIC), (IIA, IIIA), (IIC, IIIA) and (IIC, IIIB), with domestic composite crude prices ranging between $8.76 and $8.79 bbl. Their average, $8.77, will be denoted as the "Low II & III" price.

[6] These four options are (IIA, IIIB), (IIA, IIID), (IIB, IIID) and (IIC, IIID), with domestic crude prices lying in the range $8.94 to $8.99. The average, $8.97, will be referred to as the "High II & III" price.

[7] Predictions of product costs for 1975, 1979 and 1985 derive from U.S. Federal Energy Administration, Office of Transportation Programs, Pricing Distortions of Petroleum Products, Conservation Paper, November 31, 1975, Table 12, p. 27.

# TABLE VI-21

## PRICES OF REFINERY IMPORTS AND PRODUCT SUPPLY PRICES
($ 1975/bbl.)

| YEAR AND OPTION | (1) COMPOSITIONS OF DOMESTIC CRUDE | (2) PRICE OF NATURAL GAS LIQUIDS | (3) SHARE OF IMPORTS | (4) PRICE OF REFINERY INTAKE | (5) SUPPLY PRICES OF PRODUCTS WHOLESALE | (6) SUPPLY PRICES OF PRODUCTS RETAIL |
|---|---|---|---|---|---|---|
| 1975 Control | $ 7.66 | $ 7.83 | 36.4% | $ 9.47 | $14.77 | $18.62 |
| 1979 Base Case | 6.84 | 7.83 | 38.5 | 9.12 | 14.67 | 18.20 |
| 1979 Low II & III | 8.77 | 7.83 | 34.5 | 10.03 | 15.58 | 19.12 |
| 1979 High II & III | 8.97 | 7.83 | 34.0 | 10.13 | 15.68 | 19.21 |
| 1979 Immediate Decontrol | 13.13 | 10.30 | 31.0 | 12.85 | 18.40 | 21.93 |
| 1985 All Cases | 13.13 | 10.30 | 37.0 | 12.85 | 18.40 | 21.93 |

[1] Assumes decontrol of NGL prices only if crude prices are decontrolled: determination of decontrol prices of NGLs is based upon the assumption of a common price per Btu with crude oil. Prices of NGLs based upon averages in last two quarters of 1975.

[2] Assumes (i) constant shares for imported products in total petroleum supplies; (ii) constant world oil prices, (iii) constant shares for NGLs in refinery inputs.

Sources: (2) FEA, API verbal information concerning prices and volumes of three NGL inputs to refineries in 1975.

(3) U.S. Bureau of Mines, "Supply and Demand of All Oils," April 1976.

(4), (5) Assumes real gross margins downstream from production of $5.29, $5.55 and $5.41 for wholesale products in 1975, 1979 and 1985, respectively; and $9.15, $9.08 and $8.84 for retailed products.

of the whole procedure and are within 0.3 percentage points of the predicted ratio of importation (Table VI-27, below). That is, once the domestic composite price is determined, the level of imports is guessed, the overall composite is computed, demand is calculated and the difference between demand and domestic production is compared to the guess. This procedure is repeated until the guess and calculation closely correspond on imports.

## Supply Prices and Market Prices

It has been assumed that overall product supply prices will be increased when crude prices rise, but in a lesser proportion, according to the size of the downstream gross margins. The actual increases in the market prices of particular products remain to be determined. It is shown in Appendix B that, if product supply prices increase by a factor $\mu$, the actual market prices of specific products will increase by the factor

$$\lambda_i = \frac{\mu\delta}{\delta - \beta_i(1+\mu)}$$

according to a simple linear model of a competitive market, with $\beta$ and $\delta$ being respectively the price elasticities of the demand for and the supply of the product. The implication is that, for a given proportional increase $\mu$ in supply prices, the actual increase in market prices cannot exceed the factor $\mu$; it will fall short of $\mu$ if demand is at all sensitive to price ($|\beta|>0$) or if changes in price are required for supply to be altered ($\delta$ is finite). Products whose demand is relatively insensitive to price, such as gasoline,[8] will receive the higher than average increase in market prices -- a phenomenon clearly reflected in the existing price structure for petroleum products.

Concerning the price elasticity of supply, it is clear from the production estimates that a low value ($\delta \approx 0.18$) is implicit in the sluggish short-run response of domestic production to the increases contemplated in domestic oil prices under the decontrol policy (Table VI-20). Such a low supply elasticity implies that the increases in market prices ($\lambda$) will be much less than the increases in supply prices ($\mu$). Given the limits to competition in the oil industry, it is more plausible to assume that sellers would be both willing and able to accept additional losses of volume in order to lessen the cuts in prices that would otherwise arise when faced with a situation of excess supply at the new supply prices. A value of unity will tentatively be applied to $\delta$ for conditions of excess supply, recognizing that the value for situations of excess demand is much closer to zero (see Appendix B).

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[8] Energy Resources Company Inc., The Elasticity of Demand for Gasoline, Final Report, for the Federal Energy Administration, 1975.

The elasticities of demand for the four principal products, accounting for four-fifths of sales by volume, are those estimated by the PIES demand model (Table VI-22). They represent long-run values and are appropriate for this analysis only on the assumption that the 1979 and 1985 prices under consideration are firmly established in the expectations of buyers and sellers at least three years in advance. Given the political situation, such an assumption is undoubtedly extreme and lower elasticities (absolute values closer to zero) would prove more appropriate. Furthermore, in the case of gasoline at least, the use of a time-series model covering solely the years 1960 to 1972 for the estimation of demand parameters in the PIES model will result in overestimation of demand elasticities.[9] For these two reasons, the actual changes in demand induced by regulatory price policy can be expected to be even smaller than the modest values to be estimated in the succeeding section.

The anticipated increases in market prices for the four principal products are presented in Table VI-23. It is assumed for simplicity that final user purchases occur for gasoline wholly at the retail (service station) stage, and for the other products entirely at the wholesale (tank wagon) stage. A constant real tax of $4.94 per barrel is assumed to apply indefinitely to all sales of gasoline;[10] no other excise taxes are considered.

Although the demand for gasoline is the least price elastic of all, the predicted price increases for this product are markedly less than for the other products, reflecting the effects of the uniquely large retail margin of, and the excise tax upon, gasoline. The general expectation is that the proportional increases in market prices will be one-half or less that in the intake price of crude.

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[9] Energy Resources, Elasticity of Demand for Gasoline, pp. 30-32.

[10] National Petroleum News, Factbook Issue, p. 83.

## TABLE VI-22

## PRICE ELASTICITIES OF LONG RUN DEMAND ($\beta_i$) FOR PETROLEUM PRODUCTS (PIES MODEL)

| | (1) RESIDENTIAL/ COMMERCIAL | (2) INDUSTRIAL UTILITIES | (3) TRANSPORTATION | (4) ALL SECTORS |
|---|---|---|---|---|
| Gasoline | - | - | - .480 | - .480 |
| Kerosine & Jet Fuel | - 1.084 | - .754 | - .245 | - .367 |
| Distillate | - .942 | - .439 | (- .475)[1] | - .695 |
| Residual | - .639 | - .439 | (- .500)[2] | - .483 |

[1] Median value for three sub-sectors.

[2] Assumed, in the absence of published information.

Source: U.S. Federal Energy Administration, 1976 National Energy Outlook, pp. C-7, C-17; aggregate values in (4) based upon volume weights derived from Table C-1, p. C-2.

## TABLE VI-23

## ANTICIPATED INCREASES IN MARKET PRICES FOR PRODUCTS[1]

(In Percent)

| YEAR AND OPTION | GASOLINE | KEROSINE & JET FUEL | DISTILLATE | RESIDUAL |
|---|---|---|---|---|
| 1979 Base Case | -1.54% | -0.50% | -0.40% | -0.46% |
| 1979 Low II & III | 1.77 | 3.97 | 3.18 | 3.65 |
| 1979 High II & III | 2.13 | 4.45 | 3.55 | 4.08 |
| 1979 Immediate Decontrol | 11.36 | 16.88 | 13.18 | 15.58 |
| 1985 All Cases | 10.55 | 16.26 | 12.72 | 14.80 |

[1] 1975 Prices as Base.

Even under complete decontrol, no product price is predicted to increase by more than 17 percent over 1975 levels.

### 3. The Prediction of Demand

The estimated changes in incomes, output and prices, weighted by the relevant demand elasticities, combine to predict the growth in product demand, as indicated by expression (2). It is assumed that uniform price changes are required for each broad product; kerosine and jet fuel are treated as fungible products for analytical convenience. Moreover, the demand for miscellaneous products, which is predicted with a multiplicity of separate simple methods in the PIES model, is assumed to grow in proportion to the composite demand for the four principal products. The effects of the decontrol are estimated on the assumptions that, firstly, decontrol of natural gas prices would accompany that of crude oil and, secondly, that the unregulated price of natural gas liquids would be set by a common price per caloric content compared to crude oil.

The predictions of demand under the different price alternatives are dominated by the price and income effects for 1979. Population effects are included, but their impact is negligible given the smallness of both the elasticity and actual population growth.[11] Predicted demand growth factors, broken down by product and sector, are displayed in Table VI-24. The full range of price options, from the declining real domestic price of the Base Case to complete decontrol, results in a maximal 7 percent range in the change of demand for products between 1975 and 1979 -- basically, 9 percent overall growth under decontrol as against 16 percent growth under a policy of price reduction. Growth in the demand for gasoline is affected least by price policy, given both its inelasticity and the unusually high distributional margins, including excise taxes, characteristic of that product. The various policy options under Stage II and III are seen to exert an insignificant influence upon the growth of demand. For no product does the higher price

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[11] The long-run income, output and population size elasticities of demand are as follows:

| | PERSONAL INCOME | OUTPUT | POPULATION SIZE |
|---|---|---|---|
| Residential/Commercial | 1.134 | - | -.134 |
| Industrial | - | 1.00 | 0.0 |
| Transportation | .976 | - | .024 |

## TABLE VI-24

## PERCENTAGE CHANGES IN DEMAND FOR PETROLEUM PRODUCTS, BY PRODUCT, 1979 AND 1985

| | INCREASES IN DEMAND (1975 BASE) | | | | |
|---|---|---|---|---|---|
| YEAR AND OPTION | GASOLINE | KEROSINE & JET FUEL | DISTILLATE | RESIDUAL | ALL[1] |
| 1979 Base Case | 16.6 | 15.9 | 16.0 | 16.0 | 16.3 |
| 1979 Low II & III | 15.0 | 14.3 | 13.5 | 14.0 | 14.4 |
| 1979 High II & III | 14.9 | 14.1 | 13.3 | 13.8 | 14.2 |
| 1979 Immediate Decontrol | 10.4 | 9.6 | 6.6 | 8.2 | 9.1 |
| 1985 All Cases[2] | 39.7 | 38.5 | 35.6 | 37.3 | 38.2 |

---

[1] Assumes that demand for miscellaneous products grows in proportion to demand for the four major products; weighted by shares of demand in 1975, by volume.

[2] The 1985 figures are dominated by the economic growth forecast between 1979 and 1985.

option reduce the growth of demand by 1979 by more than 0.2 percentage points.

The estimates of volumes demanded, broken down by sector, are reported in Table VI-25. The transportation sector, with its large price-inelastic demand for gasoline, is less affected by the various price regulations than are the other sectors. Regional breakdowns of growth factors are reported in Table VI-26.[12]

Given the estimates of domestic crude production at the various price levels, oil imports can be predicted as the difference between these demand estimates and the production figures (Table VI-27). The allowance of higher prices for domestic crude oil does indeed serve to reduce the share of imports, both by stimulating domestic production and restraining demand. At the same time, not even the great differences in price policy involved in the "Base Case" and "decontrol" alternatives serve to move the predicted import share outside the range 30 to 40 percent of demand in 1979. Complete decontrol is expected to restrict the share of imports to 30 percent of demand in 1979, while, at the other extreme, the Base Case policy of price reduction implies no more than a 39 percent rate of importation in that year.

The contrasts between the various price options envisaged under Stages II and III rulemaking are a miniature version of the contrast between the Base Case and decontrol policies. Given the continuation of at least a 30 percent ratio of importation under any option, the differences between the high and low price options under Stages II and III are of a strictly secondary order of magnitude, offering a reduction of only 1.4 percent in 1979 imports.

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[12] National weights are used for the aggregation across products within each region.

## TABLE VI-25

## PREDICTED DEMAND FOR PETROLEUM PRODUCTS BY SECTOR, 1979 AND 1985

(Thousands of Barrels per Day)

| YEAR AND OPTION | RESIDENTIAL/ COMMERCIAL | INDUSTRIAL | TRANSPORTATION | ALL |
|---|---|---|---|---|
| 1975 Actual | 2,952 | 4,525 | 8,714 | 16,291 |
| 1979 Base Case | 3,414 | 5,405 | 10,149 | 18,968 |
| 1979 Low II & III | 3,317 | 5,325 | 10,012 | 18,654 |
| 1979 High II & III | 3,307 | 5,316 | 9,998 | 18,621 |
| 1979 Immediate Decontrol | 3,042 | 5,093 | 9,621 | 17,750 |
| 1985 All Cases | 3,882 | 6,720 | 12,168 | 22,770 |

## TABLE VI-26

## PREDICTED PERCENTAGE INCREASES RELATIVE TO 1975 IN THE DEMAND FOR PETROLEUM PRODUCTS, BY REGION, 1979 AND 1985

| YEAR AND OPTION | NORTH EAST | MID-ATLANTIC | E.N. CENTRAL | W.N. CENTRAL | SOUTH ATLANTIC | E.S. CENTRAL | W.S. CENTRAL | MOUN-TAIN | PACIFIC |
|---|---|---|---|---|---|---|---|---|---|
| 1979 Base Case | 15.8 | 14.8 | 14.3 | 15.1 | 18.8 | 18.1 | 17.3 | 17.0 | 16.3 |
| 1979 Low II & III | 13.9 | 12.9 | 12.5 | 13.2 | 16.9 | 16.2 | 15.5 | 15.2 | 14.4 |
| 1979 High II & III | 13.7 | 12.7 | 12.3 | 13.0 | 16.7 | 16.0 | 15.3 | 15.0 | 14.2 |
| 1979 Immediate Decontrol | 8.5 | 7.5 | 7.1 | 7.8 | 11.6 | 10.8 | 10.1 | 9.8 | 9.1 |
| 1985 All Cases | 30.0 | 27.1 | 23.3 | 32.0 | 36.4 | 37.6 | 35.1 | 31.0 | 31.9 |

## TABLE VI-27

## PREDICTED PRODUCTION, DEMAND AND IMPORTS OF ALL OILS, 1979 AND 1985

(Millions of Barrels Per Day)

| YEAR | OPTION | DOMESTIC CRUDE PRODUCTION[1] | DEMAND FOR PRODUCTS | IMPORTS[2] | IMPORT SHARES | |
|---|---|---|---|---|---|---|
| | | | | | PREDICTED | ASSUMED |
| 1975 | Actual | 9.99 | 16.29 | 6.30 | | |
| 1979 | Base Case | 9.75 | 18.97 | 7.35 | 38.8% | 38.5 |
| 1979 | Low II & III | 10.42 | 18.65 | 6.39 | 34.3 | 34.5 |
| 1979 | High II & III | 10.48 | 18.62 | 6.30 | 33.9 | 34.0 |
| 1979 | Immediate Decontrol | 10.68 | 17.76 | 5.33 | 30.0 | 31.0 |
| 1985 | All Cases | 12.21 | 22.77 | 8.61 | 36.5 | 37.0 |

[1] Crude oil and lease condensate.

[2] Including products; assumes that input of NGLs remains at 9.9 percent of demand and is supplied wholly from domestic sources.

# CHAPTER VII

## ENVIRONMENTAL IMPACT ANALYSIS OF ALTERNATIVE PRICING SCENARIOS

In this chapter estimates of the impacts of the several pricing option alternatives are presented and discussed. The scale for the discussion is regional and national in contrast to the discussion of potential localized impacts in Chapter IV. Differences in potential impact among the options are pointed out as well as differences relative to the present (1975) situation and relative to the situation that would result in 1979 if no action were taken (Base Case) beyond the establishment of a fixed composite and lower tier price in constant dollars.

The Base Case represents an alternative to the Stage II and Stage III options and is discussed fully in Chapter X below. It also represents the environment that will exist in 1979 without further Federal regulation, assuming market forces follow current trends. The 1975 levels, because oil production and consumption are dynamic processes and change with time, are not a proper measure of the undisturbed future environment, but are useful in assessing potential future impact relative to the world around us currently.

The differential impacts of production are discussed for each pricing option. The overall potential impact for the combined effects of production, conversion, and consumption is discussed in the framework of a single consumption scenario combining the effects of all energy forms. A single consumption scenario is sufficient to indicate the overall impacts of the pricing options. The analysis of price-induced demand changes in the previous chapter indicates that demand for all petroleum products (Table VI-27) would vary less than 0.2 percent from the highest priced options to the lower priced options, and would be only about 1.5 percent less than the Base Case. The methodology used to generate overall consumption effects is insufficiently sensitive to distinguish between levels that close together. Regional differences (Table VI-26) are, similarly, essentially indistinguishable for all options.

The impacts discussed on an aggregated basis are related to the localized effects discussed earlier in Chapter IV. These include:

- Air quality
- Water consumption

- Water quality
- Socioeconomic factors
- Other environmental effects, including oil spills

Where practical and reasonable aggregated figures have been developed by applying emission factors to national and regional production figures. The results are summarized at various points in the following discussion.

The regions discussed refer to the NPC Production Regions (see Figure VI-1, also referred to as petroleum provinces). The pricing options are defined in Chapter II and summarized in Table VII-1. The tables of residuals in this chapter are based on data represented in Appendix C.

TABLE VII-1

## SHORTHAND FOR PRICING ALTERNATIVES

| SHORTHAND | | PRICING POLICY DESCRIPTION |
|---|---|---|
| Base Case | Base Case -- | Lower tier held at $5.15 average nominal price (through May 1979); upper tier price adjusted to give $7.66 composite. |
| Stage II | Stage II -- | Composite price escalates 10 percent per year. |
| IIA | A | Same relative price increase for both tiers. |
| IIB | B | Lower tier held at constant average real price. |
| IIC | C | Lower tier held at constant average nominal price. |
| Stage III | Stage III -- | Additional incentive for special situations (composite can increase more than 10 percent per year to accommodate these). |
| IIIA | A | Tertiary production gets free market price. |
| IIIB | B | Total production from tertiary projects gets free market price. |
| IIIC | C | Redefine "strippers" to include deep onshore, plus offshore, wells. |
| IIID | D | Reduce California gravity schedule. |

## A. Environmental Impacts - 1979 Pricing Options

### 1. General Characteristics

The production levels expected under each of the alternate pricing options, the 1979 Base Case, and the current basis (1975) are given in Table VII-2 (by region) and Table VII-3 (by production technology). The increase in total production over the Base Case is shown in Table VII-2.

The effect of the various options on overall production is much less than their effect on the distribution by technology or by region. The absolute difference in total production between the most effective option (IIC-IIIA) and the lowest (IIC) is only 250,000 barrels per day out of a total of about 10,500,000 barrels per day, a variation of only about 2 percent.

Production by technology is more affected by the choice of option. Tertiary approaches are most emphasized in combinations employing option IIIB, and somewhat lesser for option IIIA. The total tertiary production under option IIIB is 520,000 barrels per day. This level is more than double the production under the lowest tertiary oriented options (IIC, IIC-IIIC and IIC-IIID).

At the national level, relative to the Base Case, differences in total production range between 6.5 percent and 9.0 percent, with the combined pricing option of IIC-IIIA giving the greatest production. Carbon dioxide-miscible gas projects range from 30,000 (same as Base Case) to 250,000 barrels per day, and those associated with in-situ combustion projects range from 10,000 (same as Base Case) to 60,000 barrels per day. Both follow nearly the same pattern with respect to the alternatives. The low estimates result from the exercise of alternatives IIC, IIC-IIIC, and IIC-IIID. An increase to 90,000 barrels per day for $CO_2$-miscible gas and 40,000 barrels per day for in-situ combustion arise from policies IIA, IIB, IIA-IIIC, IIB-IIIC, IIA-IIID, and IIB-IIID. An increase to 60,000 barrels per day in in-situ combustion production is tied to the remaining alternatives, while $CO_2$-miscible gas reaches 190,000 barrels per day under the three policies associated with option IIIA, and 250,000 barrels per day for those under IIIB.

Steam production levels respond somewhat differently. They range from 170,000 (same as Base Case) to 210,000 barrels per day. All of the highest production figures are tied to options involving either IIIA or IIIB, as was the

# TABLE VII-2

## REGIONAL PRODUCTION LEVELS -- 1979 CASES
(thousand bbl/day)

| REGION | 1975 | 1979 BASE CASE | IIA | IIB | IIC | IIA IIIA | IIB IIIA | IIC IIIA | IIA IIIB | IIB IIIB | IIC IIIB | IIA IIIC | IIB IIIC | IIC IIIC | IIA IIID | IIB IID | IIC IIID |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| NORTH SLOPE | 0 | 1,420 | 1,420 | 1,420 | 1,420 | 1,420 | 1,420 | 1,420 | 1,420 | 1,420 | 1,420 | 1,420 | 1,420 | 1,420 | 1,420 | 1,420 | 1,420 |
| 1 | 190 | 120 | 120 | 120 | 120 | 120 | 120 | 120 | 120 | 120 | 120 | 120 | 120 | 120 | 120 | 120 | 120 |
| 2 | 670 | 990 | 1,050 | 1,060 | 1,020 | 1,110 | 1,110 | 1,110 | 1,120 | 1,120 | 1,120 | 1,050 | 1,060 | 1,070 | 1,070 | 1,080 | 1,040 |
| 2A | 220 | 90 | 160 | 160 | 160 | 160 | 160 | 160 | 160 | 160 | 160 | 160 | 160 | 160 | 160 | 160 | 160 |
| 3 | 140 | 180 | 180 | 180 | 180 | 180 | 180 | 180 | 180 | 180 | 180 | 180 | 180 | 180 | 180 | 180 | 180 |
| 4 | 620 | 470 | 540 | 540 | 540 | 540 | 540 | 540 | 540 | 540 | 540 | 540 | 540 | 540 | 540 | 540 | 540 |
| 5 | 2,050 | 1,660 | 1,690 | 1,690 | 1,670 | 1,750 | 1,750 | 1,750 | 1,780 | 1,760 | 1,780 | 1,690 | 1,690 | 1,670 | 1,690 | 1,690 | 1,670 |
| 6 | 2,440 | 2,630 | 2,980 | 2,980 | 2,950 | 2,960 | 2,910 | 3,030 | 2,890 | 2,830 | 2,970 | 2,980 | 2,980 | 2,950 | 2,980 | 2,980 | 2,950 |
| 6A | 990 | 1,350 | 1,390 | 1,390 | 1,390 | 1,380 | 1,380 | 1,390 | 1,370 | 1,360 | 1,380 | 1,420 | 1,420 | 1,420 | 1,390 | 1,390 | 1,390 |
| 7 | 730 | 520 | 560 | 560 | 560 | 540 | 530 | 560 | 520 | 500 | 540 | 560 | 560 | 560 | 560 | 560 | 560 |
| 8-9-10 | 220 | 160 | 210 | 210 | 210 | 210 | 210 | 210 | 210 | 210 | 210 | 210 | 210 | 210 | 210 | 210 | 210 |
| 11 | 110 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 |
| 11A | 0 | 60 | 60 | 60 | 60 | 60 | 60 | 60 | 60 | 60 | 60 | 60 | 60 | 60 | 60 | 60 | 60 |
| NATIONAL TOTAL | 8,380 | 9,750 | 10,460 | 10,470 | 10,380 | 10,530 | 10,470 | 10,630 | 10,470 | 10,400 | 10,580 | 10,430 | 10,500 | 10,410 | 10,480 | 10,490 | 10,400 |
| PERCENT INCREASE OVER 1975 BASE CASE | - | - | 7.3 | 7.4 | 6.5 | 8.0 | 7.4 | 9.0 | 7.4 | 6.7 | 8.5 | 7.6 | 7.7 | 6.8 | 7.5 | 7.6 | 6.7 |

## TABLE VII-3

## PRODUCTION LEVELS BY TECHNOLOGY - 1979 CASES
(thousand bbl/day)

| TECHNOLOGY | 1975 | 1979 BASE CASE | IIA | IIB | IIC | IIA IIIA | IIB IIIA | IIC IIIA | IIA IIIB | IIB IIIB | IIC IIIB | IIA IIIC | IIB IIIC | IIC IIIC | IIA IIID | IIB IIID | IIC IIID |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| OFFSHORE | 1,400 | 1,620 | 1,730 | 1,730 | 1,730 | 1,720 | 1,720 | 1,730 | 1,710 | 1,700 | 1,720 | 1,760 | 1,760 | 1,760 | 1,730 | 1,730 | 1,730 |
| ONSHORE | 6,715 | 7.920 | 8,430 | 8,430 | 8,440 | 8,350 | 8,290 | 8,440 | 8,240 | 8,180 | 8,340 | 8,430 | 8,430 | 8,440 | 8,450 | 8,450 | 8,460 |
| STEAM INJECTION | 180 | 170 | 170 | 180 | 170 | 210 | 210 | 210 | 210 | 210 | 210 | 170 | 180 | 170 | 170 | 180 | 170 |
| IN-SITU COMBUSTION | 5 | 10 | 40 | 40 | 10 | 60 | 60 | 60 | 60 | 60 | 60 | 40 | 40 | 10 | 40 | 40 | 10 |
| $CO_2$/MISCIBLE | 80 | 30 | 90 | 90 | 30 | 190 | 190 | 190 | 250 | 250 | 250 | 90 | 90 | 30 | 90 | 90 | 30 |
| MICELLAR-POLYMER | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| TOTAL | 8,380 | 9,750 | 10,460 | 10,470 | 10,380 | 10,530 | 10,470 | 10,630 | 10,470 | 10,400 | 10,580 | 10,490 | 10,500 | 10,410 | 10,480 | 10,490 | 10,400 |

case with in-situ combustion. Of the remaining options, those associated with IIB registered 180,000 barrels per day, and the rest associated with IIA and IIC were identical to the Base Case.

Oil recovery in 1979 from conventional onshore activities ranges from 3.3 percent to 6.8 percent above the Base Case levels. Those in the range of 6.4 percent to 6.8 percent are induced by all of the IIIC and IIID options, the solitary II policies and the IIC-IIIA policy. The IIIB options cause differences of 3.3 percent to 5.3 percent, and the IIA-IIIA and IIB-IIIA policies yield greater levels of 5.4 percent and 4.7 percent respectively.

Offshore differences also register a rather small variation among alternatives, with a range of 4.9 percent to 8.6 percent. The solitary case II options and those involving IIID produce a change of 6.8 percent, as does option IIC-IIIA. The IIIC policies are responsible for the maximum difference of 8.6 percent, and the remaining alternatives produce changes of 4.9 percent to 6.2 percent.

Regional differences, from option to option, are quite small, about 3 to 4 percent at most. The large differences in output for some of the tertiary methods are masked by the predominant production by conventional methods in the three regions (Regions 2, 5, and 6) where the advanced methods are likely to be employed.

Growth of tertiary projects is assumed to occur in the same regions where the techniques are being used currently. No significant output from micellar-polymer techniques is expected through 1979.

Steam injection projects are located entirely in California (Region 2), confined to certain areas of the state. Counties containing these projects are Kern, Fresno, Orange, Santa Barbara, and Monterey Counties. Table IV-9 lists these projects in some detail.

The $CO_2$-miscible gas projects of any consequence presently number less than 10 and fall in Regions 5 and 6. The largest were located in the Texas counties of Scurry, Anderson, Henderson, and Crane. Smaller developments were found in Crane and Upton Counties. The in-situ combustion projects were dominated by the installations in Bossier Parish, Louisiana (Region 6), with other minor producers in Jasper County, Mississippi (Region 6) and in Kern and Orange Counties, California (Region 2).

## 2. Air Quality

Estimates of atmospheric emissions for the pricing options are displayed in Tables VII-4 and VII-5 (by region) and in Tables VII-6 through VII-10 (by technology and pollutant species).

### 2.1 Particulate Emissions

Particulate emissions arise, under the assumptions employed in this study, entirely from steam injection, due to the combustion of fuel to generate heat. The several options emphasizing these tertiary approaches produce, as a direct consequence, the largest particulate emissions. These are the six options involving either the IIIB or IIIC option (see Table VII-6). Emissions in any of the maximal options are 16.8 tons per day, about 25 percent larger than the smallest figure for the Base Case or several of the lowest output options (IIA, IIC, etc.) These emissions would occur entirely in Region 2 (California).

### 2.2 Nitrogen Oxide Emissions

The pattern for nitrogen oxides (Table VII-7) is essentially identical to that for particulates, since, as above, steam injection is assumed to be the only significant source of $NO_x$ on an aggregated basis. Other sources of $NO_x$ include compressors associated with both in-situ combustion and $CO_2$-miscible techniques. Production by these methods will not have achieved sufficient levels by 1979 to create regional problems. Localized impacts, as discussed earlier in Chapter IV, may arise in the vicinity of large, centralized facilities.

### 2.3 Sulfur Oxide Emissions

Sulfur oxides (Table VII-8) also follow the same pattern as that for particulates and nitrogen oxides.

### 2.4 Hydrocarbon Emissions

Hydrocarbon emissions arise mainly from both steam injection and in-situ combustion production techniques. Emissions from other technologies are considered insignificant in comparison. The largest emissions are associated with the tertiary recovery maximizing options (all combinations of IIIA or IIIB). In these cases, the emissions (79.6 tons/day) are more than four times those arising from the

## TABLE VII-4

## REGION 2 ATMOSPHERIC EMISSIONS - 1979 CASES
(tons/day)

| POLLUTANT | 1975 | 1979 BASE CASE | IIA | IIB | IIC | IIA IIIA | IIB IIIA | IIC IIIA | IIA IIIB | IIB IIIB | IIC IIIB | IIA IIIC | IIB IIIC | IIC IIIC | IIA IIID | IIB IID | IIC IIID |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| PARTICULATES | 14.4 | 13.6 | 13.6 | 14.4 | 13.6 | 16.8 | 16.8 | 16.8 | 16.8 | 16.8 | 16.8 | 13.6 | 14.4 | 13.6 | 13.6 | 14.4 | 13.6 |
| $NO_x$ | 87.1 | 82.3 | 82.3 | 87.1 | 82.3 | 101.6 | 101.6 | 101.6 | 101.6 | 101.6 | 101.6 | 82.3 | 87.1 | 82.3 | 82.3 | 87.1 | 82.3 |
| $SO_x$ | 196.2 | 185.3 | 185.3 | 196.2 | 185.3 | 228.9 | 228.9 | 228.9 | 228.9 | 228.9 | 228.9 | 185.3 | 196.2 | 185.3 | 185.3 | 196.2 | 185.3 |
| HYDROCARBONS | 2.9 | 2.7 | 28.1 | 28.3 | 2.7 | 41.5 | 41.5 | 41.5 | 41.5 | 41.5 | 41.5 | 28.1 | 28.3 | 2.7 | 28.1 | 28.3 | 2.7 |
| CO | 0.6 | 0.5 | 125.5 | 125.6 | 0.5 | 188.2 | 188.2 | 188.2 | 188.2 | 188.2 | 188.2 | 125.5 | 125.6 | 0.5 | 125.5 | 125.6 | 0.5 |

## TABLE VII-5

## REGION 6 ATMOSPHERIC EMISSIONS - 1979 CASES
(tons/day)

| POLLUTANT | 1975 | 1979 BASE CASE | IIA | IIB | IIC | IIA IIIA | IIB IIIA | IIC IIIA | IIA IIIB | IIB IIIB | IIC IIIB | IIA IIIC | IIB IIIC | IIC IIIC | IIA IIID | IIB IID | IIC IIID |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| HYDROCARBONS | 6.4 | 12.7 | 25.4 | 25.4 | 12.7 | 38.1 | 38.1 | 38.1 | 38.1 | 38.1 | 38.1 | 25.4 | 25.4 | 12.7 | 25.4 | 25.4 | 12.7 |
| CO | 31.3 | 62.5 | 125.0 | 125.0 | 62.5 | 187.5 | 187.5 | 137.5 | 187.5 | 187.5 | 187.5 | 125.0 | 125.0 | 62.5 | 125.0 | 125.0 | 62.5 |

## TABLE VII-6

## ATMOSPHERIC PARTICULATE EMISSIONS BY TECHNOLOGY - 1979 OPTIONS
(tons/day)

| TECHNOLOGY | 1975 | 1979 BASE CASE | IIA | IIB | IIC | IIA IIIA | IIB IIIA | IIC IIIA | IIA IIIB | IIB IIIB | IIC IIIB | IIA IIIC | IIB IIIC | IIC IIIC | IIA IIID | IIB IID | IIC IIID |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| STEAM INJECTION[1] | 14.4 | 13.6 | 13.6 | 14.4 | 13.6 | 16.8 | 16.8 | 16.8 | 16.8 | 16.8 | 16.8 | 13.6 | 14.0 | 13.6 | 13.6 | 14.4 | 13.6 |

## TABLE VII-7

## ATMOSPHERIC $NO_x$ EMISSIONS BY TECHNOLOGY - 1979 OPTIONS
(tons/day)

| TECHNOLOGY | 1975 | 1979 BASE CASE | IIA | IIB | IIC | IIA IIIA | IIB IIIA | IIC IIIA | IIA IIIB | IIB IIIB | IIC IIIB | IIA IIIC | IIB IIIC | IIC IIIC | IIA IIID | IIB IID | IIC IIID |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| STEAM INJECTION[1] | 87.1 | 82.3 | 82.3 | 87.1 | 82.3 | 101.6 | 101.6 | 101.6 | 101.6 | 101.6 | 101.6 | 82.3 | 87.1 | 82.3 | 82.3 | 87.1 | 82.3 |

---

[1] Emissions from other technologies are assumed to be zero.

## TABLE VII-8

## ATMOSPHERIC $SO_x$ EMISSIONS BY TECHNOLOGY - 1979 OPTIONS
(tons/day)

| TECHNOLOGY | 1975 | 1979 BASE CASE | IIA | IIB | IIC | IIA IIIA | IIB IIIA | IIC IIIA | IIA IIIB | IIB IIIB | IIC IIIB | IIA IIIC | IIB IIIC | IIC IIIC | IIA IIID | IIB IID | IIC IIID |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| STEAM INJECTION [1] | 196.2 | 185.3 | 185.3 | 196.2 | 185.3 | 228.9 | 228.9 | 228.9 | 228.9 | 228.9 | 228.9 | 185.3 | 196.2 | 185.3 | 185.3 | 196.2 | 185.3 |

## TABLE VII-9

## ATMOSPHERIC HYDROCARBONS EMISSIONS BY TECHNOLOGY - 1979 OPTIONS
(tons/day)

| TECHNOLOGY | 1975 | 1979 BASE CASE | IIA | IIB | IIC | IIA IIIA | IIB IIIA | IIC IIIA | IIA IIIB | IIB IIIB | IIC IIIB | IIA IIIC | IIB IIIC | IIC IIIC | IIA IIID | IIB IID | IIC IIID |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| STEAM INJECTION | 2.9 | 2.7 | 2.7 | 2.9 | 2.7 | 3.4 | 3.4 | 3.4 | 3.4 | 3.4 | 3.4 | 2.7 | 2.9 | 2.7 | 2.7 | 2.9 | 2.7 |
| IN-SITU COMBUSTION | 6.4 | 12.7 | 50.8 | 50.8 | 12.7 | 76.2 | 76.2 | 76.2 | 76.2 | 76.2 | 76.2 | 50.8 | 50.8 | 12.7 | 50.8 | 50.8 | 12.7 |
| TOTAL | 9.3 | 15.4 | 53.5 | 53.7 | 15.4 | 79.6 | 79.6 | 79.6 | 79.6 | 79.6 | 79.6 | 53.5 | 53.7 | 15.4 | 53.5 | 53.7 | 15.4 |

## TABLE VII-10

## ATMOSPHERIC CO EMISSIONS BY TECHNOLOGY - 1979 OPTIONS
(tons/day)

| TECHNOLOGY | 1975 | 1979 BASE CASE | IIA | IIB | IIC | IIA IIIA | IIB IIIA | IIC IIIA | IIA IIIB | IIB IIIB | IIC IIIB | IIA IIIC | IIB IIIC | IIC IIIC | IIA IIID | IIB IID | IIC IIID |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| STEAM INJECTION | 0.6 | 0.5 | 0.5 | 0.6 | 0.5 | 0.7 | 0.7 | 0.7 | 0.7 | 0.7 | 0.7 | 0.5 | 0.6 | 0.5 | 0.5 | 0.6 | 0.5 |
| IN-SITU COMBUSTION | 31.3 | 62.5 | 250.0 | 250.0 | 62.5 | 375.0 | 375.0 | 375.0 | 375.0 | 375.0 | 375.0 | 250.0 | 250.0 | 62.5 | 250.0 | 250.0 | 62.5 |
| TOTAL | 31.9 | 63.0 | 250.5 | 250.6 | 63.0 | 375.7 | 375.7 | 375.7 | 375.7 | 375.7 | 375.7 | 250.5 | 250.6 | 63.0 | 250.5 | 250.6 | 63.0 |

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[1] Emissions from other technologies are assumed to be zero.

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APPENDIX D IMPACTS OF OIL SPILLS D-1

APPENDIX E STRIPPER WELL PRODUCTION E-1

APPENDIX F DERIVATION OF SUPPLY CURVES F-1

APPENDIX G OPTION-INDEPENDENT PRODUCTION AND LOWER TIER PRODUCTION G-1

Base Case or several other options (IIC, etc.). Most of the difference is due to the large increase in in-situ combustion which would be generated in the high tertiary incentives cases.

These hydrocarbon emissions (Tables VII-4 and VII-5) arise in Region 2 (California) and in Region 6 (Gulf Coast). Region 2 shows very large differences among the options, with the maximum cases about 15 times the smallest. The swing in Region 6 is not as large; the ratio of largest to smallest is about 3. As will be discussed below, the persistent oxidants problem in California adds considerable significance to the large differences between options. The large increase is due principally to in-situ combustion.

### 2.5 Carbon Monoxide Emissions

CO (Table IV-10) shows patterns similar to hydrocarbons, as it arises from the same sources. In-situ combustion is, by far, the largest potential source. The swings are even larger for CO than hydrocarbons. In Region 2, the ratio of largest to smallest is over 300. This large value reflects the complete absence of in-situ projects under the lowest options. In Region 6, the differences are less, about a factor of 3.

### 2.6 Impact of Air Emissions

Outside of localized problems, which cannot be pinpointed in this analysis, one major consequence of these emissions is the constraints that might be placed on the projects located in non-attainment areas or air quality management areas (AQMA).

Of the five California counties supporting steam projects, Santa Barbara and Monterey Counties are not AQMA's; the others, however, are (see Appendix J). Orange County is part of the South Coast Air Basin, and borders on Los Angeles County. This region is monitored closely for all five of the criteria pollutants. Kern County is listed as a potential problem area for particulates, carbon monoxide, and oxidants, while Fresno County is cited for particulates and oxidants. The 1974 NAAQS attainment status of these areas shows that particulate violations occurred in all of the counties except Santa Barbara. Nitrogen dioxide violations were recorded in Orange County, oxidants violated standards in all areas, carbon monoxide in all but Monterey and Santa Barbara, and sulfur dioxide violations were reported in none of the areas. Reports for 1975 indicate that the particulates problem has not been significantly reduced. No additional counties are estimated to have violated nitrogen dioxide standards. California in-situ combustion projects of note are presently located in two of the above counties: Kern and Orange.

The particulates and hydrocarbon emissions in California are likely to be taken into account in allocating emissions levels permitted in new source development in all non-attainment regions.

CO emissions, although occurring in non-attainment areas in both California and the Gulf Coast, would probably not enter into any similar policy. CO non-attainment is almost universally a consequence of automobile exhaust-induced hot spots in congested urban areas. CO emissions from remote oilfield projects would not add materially to these highly localized problem areas.

In-situ projects currently located in Bossier Parish, Louisiana (Region 6) are in both a non-attainment area and an AQMA for particulate emissions. Future large-scale expansion may be inhibited by this constraint.

Localized potential problems (exceeding short- or long-term NAAQS) would be prevented by requirements set by state agencies. No project can cause standards to be exceeded. Technology is available in all cases to meet any such requirements. Use of low sulfur fuels, electric motors, hydrocarbon recovery systems, baghouses, etc., would permit projects to conform to local environmental conditions. Application of these controls might also be sufficient to escape regulation under non-attainment or AQMA policies.

Atmospheric emissions from the total production/consumption scenario are indistinguishable from one option to another. Consumption emissions which are alike for both domestic and imported oil are so much greater than production emissions that the differences among the options identified in the tables above are completely masked. The overall demand for petroleum production is almost identical among all the options (see Chapter VI).

There is one exception to this outcome of an analysis of total energy consumption. In Region 2, sulfur oxide emissions show a small but significant difference between the tertiary-enhancing options (combinations of IIIA and IIIB) and the other options. In the case of maximum tertiary output, $SO_x$ emissions would be about 1,809 tons/day compared to about 1,766 for the smallest options (IIA, IIC, etc.).

The difference here, about 2.4 percent, is much less than the difference considering only production, which is about 55 percent.

### 3. Water Consumption

The water requirements associated with production follow quite closely the magnitude of the total production levels induced by each option (Table VII-2), in spite of some difference among technologies. This is a consequence of the predominance of onshore conventional production. Thus, overall national water requirements would be essentially equal for all pricing options. Local requirements, however, will depend on the nature of technology generally employed and on the impact of the pricing options.

The level of water consumption by onshore petroleum extraction operations in the producing regions depends directly on the recovery technology utilized. Primary recovery techniques by definition consume no water. Production brines withdrawn with the oil may be disposed of on the surface or reinjected into the ground either as a disposal technique or for secondary recovery via waterflooding. Obviously, offshore operations present few water supply problems. Waterflooding is heavily utilized now in all producing regions and accounts for the great bulk of secondary recovery operations (i.e., nearly 40 percent of total U.S. oil production). Of the major producing states, Wyoming relies most heavily on enhanced recovery with waterflooding, which accounts for about 80 percent of total state production. Texas and Oklahoma rely on waterflooding for about half their production, with California somewhat less dependent on this technique (but when combined with water-intensive steam injection it accounts for just under 50 percent). Only Louisiana, among the major producing states, has a relatively low (less than 15 percent) current dependence on waterflooding due to high primary productivity. But the need for enhanced recovery there can be expected to increase as oil fields become more depleted.

The quantity of water injected necessarily varies widely depending on the physical characteristics of the formation and the age of the development. Water-injected to oil-produced ratios range from less than 1 to over 75, with most major developments falling in the 1 to 20 range.

It is difficult to estimate the overall freshwater demand, since produced brine, water from saline aquifers and sea water are used to the maximum extent feasible depending on availability and compatibility. For example, in Oklahoma in 1967 salt water makeup totalled 2,239 million barrels (797 from oil wells, 1,442 from salt water wells) while freshwater makeup totalled only 161 million barrels (106.5 from surface water, 54.5 from wells).[1] The freshwater consumed represents an irretrievable resource.

One tertiary recovery technique in particular in use now is water-intensive and places potential demands on freshwater supplies. Steam injection, utilized almost wholly in California, uses an average of 5.2 barrels of water as steam per barrel of oil produced. In order to avoid boiler corrosion and fouling, high quality water is required, usually necessitating treatment of brines or utilization of freshwater. Efforts are underway to design boilers compatible with high ion-content brines.

The problem of freshwater availability and consumption will be magnified by considerable growth in conventional onshore production under all of the pricing options.

In California (Region 2), conventional onshore recovery is expected to increase from 490 thousand barrels per day in 1975 to the range of 820 (Base Case) to the range of 1,020 to 1,120 thousand barrels per day in 1979 depending on the option. This represents a substantial increase and may pose a threat to water supplies if salt water makeup is not secured in large volumes. Assuming that salt water is used for makeup where it is feasible and that steam projects are the only ones demanding freshwater, Table VII-11 indicates comparative freshwater requirements for California where all steam projects are predicted to take place. The difference of 200,000 barrels of water per day between the Base Case and the most water-intensive cases (150,000 barrels over 1975) is about 9,500 acre-feet per year. Compared to the approximately 15 million acre-feet pumped from groundwater reservoirs annually in California this would not appear to be a significant amount, but local problems that may occur should not be overlooked.

### 4. Water Quality

Water quality impacts onshore derive from several aspects of oil recovery. These are largely dependent on the

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[1] Oklahoma Secondary Recovery Committee, Secondary Recovery and Pressure Maintenance Operations, Interstate Oil Compact Commission, January 1, 1968, p. 1.

## TABLE VII-11

## COMPARISON OF FRESHWATER DEMANDS[1] FOR THE DIFFERENT 1979 PRICING POLICIES IN CALIFORNIA

| | FRESHWATER DEMAND (Mbbl/d) |
|---|---|
| 1975 | 900 |
| Base Case | 850 |
| IIA | 850 |
| IIB | 900 |
| IIC | 850 |
| IIA, IIIA | 1,050 |
| IIB, IIIA | 1,050 |
| IIC, IIIA | 1,050 |
| IIA, IIIB | 1,050 |
| IIB, IIIB | 1,050 |
| IIC, IIIB | 1,050 |
| IIA, IIIC | 850 |
| IIB, IIIC | 900 |
| IIC, IIIC | 850 |
| IIA, IIID | 850 |
| IIB, IIID | 900 |
| IIC, IIID | 850 |

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[1] Assumes freshwater is demanded for steam projects only at 5 barrels water per barrel of oil produced.

technologies employed in production. Groundwater contamination is by far the greatest threat and risk. Leakage of contaminated brine or chemical laden waterfloods may occur through well or formation failure. Pipeline spills and seepage from disposal pits are also sources of surface water contamination.

The impacts depend on the composition of the discharges, which are highly variable from site to site. Concentrations and composition of both hydrocarbon and trace metal pollutants are highly variable (see Chapter IV and Appendix A). As a practical surrogate for estimating and discussing water quality impacts, a discussion of total organic emissions is appropriate.

Estimates of organic loadings are presented in Table VII-12 (by technology) and in Table VII-13 (by region). The total quantities of organic emissions are only slightly influenced by the pricing option policy. The difference between the highest and lowest options is only about 2.4 percent. The highest values are associated with the several options that lead to the highest offshore production (combinations of IIIC). These options provide for a redefinition of some offshore production to the stripper category.

Conventional production methods, both onshore and offshore, produce the major source of organic pollution (Table VII-12). On a regional basis (Table VII-13), Region 6A, offshore Gulf Coast, is the most highly impacted, with about half the loadings being produced there. Regional differences from option to option are small. In many regions, no change is evident.

High onshore production levels in Regions 2, 5, and 6 occur in areas with potential groundwater problems, where any contamination of underground formation could leave a substantial deleterious effect (see Section D in Chapter IV for further discussion).

Demands for ground water are high in Texas and Oklahoma. Recharge rates are not sufficient to meet withdrawals in much of Texas and western Oklahoma where substantial oil activity takes place. Similar circumstances exist in California, where overdraft and salt water intrusion mean contamination could seriously exacerbate the water supply problem.

The major water quality problems posed offshore are by well failure, release of produced brines and pipeline spills. Minor effects are attributable to human waste disposal and deck-washings. On a per barrel of oil basis, offshore organic releases are approximately 10 times as great as onshore, which explains why the contamination in the offshore

## TABLE VII-12

## ORGANIC LOADINGS BY TECHNOLOGY - 1979 OPTIONS
(tons/day)

| TECHNOLOGY | 1975 | 1979 BASE CASE | IIA | IIB | IIC | IIA IIIA | IIB IIIA | IIC IIIA | IIA IIIB | IIB IIIB | IIC IIIB | IIA IIIC | IIB IIIC | IIC IIIC | IIA IIID | IIB IID | IIC IIID |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| OFFSHORE | 35.4 | 41.0 | 43.8 | 43.8 | 43.8 | 43.5 | 43.5 | 43.8 | 43.3 | 43.0 | 43.5 | 44.5 | 44.5 | 44.5 | 43.8 | 43.8 | 43.8 |
| ONSHORE | 19.6 | 23.1 | 24.6 | 24.6 | 24.6 | 24.4 | 24.2 | 24.6 | 24.1 | 23.9 | 24.4 | 24.6 | 24.6 | 24.6 | 24.7 | 24.7 | 24.7 |
| STEAM INJECTION | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 |
| IN-SITU COMBUSTION | 0.0 | 0.0 | 0.1 | 0.1 | 0.0 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.1 | 0.1 | 0.0 | 0.1 | 0.1 | 0.0 |
| $CO_2$/MISCIBLE | 0.2 | 0.1 | 0.3 | 0.3 | 0.1 | 0.6 | 0.6 | 0.6 | 0.7 | 0.7 | 0.7 | 0.3 | 0.3 | 0.1 | 0.3 | 0.3 | 0.1 |
| MICELLAR-POLYMER | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| TOTAL | 55.8 | 64.7 | 69.3 | 69.3 | 69.0 | 69.2 | 69.0 | 69.8 | 68.8 | 68.4 | 69.4 | 70.0 | 70.0 | 69.8 | 69.3 | 69.3 | 69.1 |

## TABLE VII-13

## REGIONAL ORGANIC POLLUTANT LOADINGS - 1979 CASES
(tons/day)

| REGION | 1975 | 1979 BASE CASE | IIA | IIB | IIC | IIA IIIA | IIB IIIA | IIC IIIA | IIA IIIB | IIB IIIB | IIC IIIB | IIA IIIC | IIB IIIC | IIC IIIC | IIA IIID | IIB IID | IIC IIID |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| NORTH SLOPE | 0 | 4.1 | 4.1 | 4.1 | 4.1 | 4.1 | 4.1 | 4.1 | 4.1 | 4.1 | 4.1 | 4.1 | 4.1 | 4.1 | 4.1 | 4.1 | 4.1 |
| 1 | 4.8 | 3.0 | 3.0 | 3.0 | 3.0 | 3.0 | 3.0 | 3.0 | 3.0 | 3.0 | 3.0 | 3.0 | 3.0 | 3.0 | 3.0 | 3.0 | 3.0 |
| 2 | 2.0 | 2.9 | 3.0 | 3.1 | 3.0 | 3.2 | 3.2 | 3.2 | 3.3 | 3.3 | 3.3 | 3.1 | 3.1 | 3.0 | 3.1 | 3.2 | 3.0 |
| 2A | 5.6 | 2.3 | 4.0 | 4.0 | 4.0 | 4.0 | 4.0 | 4.0 | 4.0 | 4.0 | 4.0 | 4.0 | 4.0 | 4.0 | 4.0 | 4.0 | 4.0 |
| 3 | 0.4 | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 |
| 4 | 1.8 | 1.4 | 1.6 | 1.6 | 1.6 | 1.6 | 1.6 | 1.6 | 1.6 | 1.6 | 1.6 | 1.6 | 1.6 | 1.6 | 1.6 | 1.6 | 1.6 |
|  | 0.0 | 4.8 | 4.9 | 4.9 | 4.9 | 5.1 | 5.1 | 5.1 | 5.2 | 5.2 | 5.2 | 4.9 | 4.9 | 4.9 | 4.9 | 4.9 | 4.9 |
| 6 | 7.1 | 7.7 | 8.7 | 8.7 | 8.6 | 8.6 | 8.5 | 8.8 | 8.4 | 8.3 | 8.7 | 8.7 | 8.7 | 8.6 | 8.7 | 8.7 | 8.6 |
| [illegible] | [illegible] | 34.1 | 35.2 | 35.2 | 35.2 | 34.9 | 34.9 | 35.2 | 34.7 | 34.4 | 34.9 | 35.9 | 35.9 | 35.9 | 35.2 | 35.2 | 35.2 |
|  | 2.1 | 1.5 | 1.6 | 1.6 | 1.6 | 1.6 | 1.5 | 1.6 | 1.5 | 1.5 | 1.6 | 1.6 | 1.6 | 1.6 | 1.6 | 1.6 | 1.6 |
| [illegible] 10 | 0.6 | 0.5 | 0.6 | 0.6 | [illegible] | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 |
| 11 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 |
| 11A | 0 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | [illegible] |
| TOTAL[1] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] | [illegible] |

regions is greater than any other. The impacts offshore are greatly affected by localized dispersion and assimilation characteristics and ecological system characteristics (see Appendix A). In some cases, such as Hackberry Bay in Louisiana, the degree of enclosure of the estuarine system makes it highly susceptible. This area has great commercial fishery importance to the region; even small incremental changes, therefore, could assume potential significance. If the proposed EPA regulations prohibiting brine discharges in near-offshore waters become finalized, then the potential impacts in places such as Hackberry Bay will be avoided. There is very little difference in offshore production and the concomitant release of organic pollutants between the Base Case and any of the pricing options in Regions 6A and 11A (Table VII-13). In both regions, production levels would exceed current output. Region 2A, California offshore, exhibits a different pattern. Production would drop quite sharply, over a factor of 2, in the absence of any of the pricing options. All of the options would restore some production but not sufficient to return to preexisting (1975) levels.

### 5. Socioeconomic Factors

All of the pricing options would reduce demand for imported oil, lowering the flow of overseas expenditures. Since overall demand for petroleum products is essentially unaffected by any of the options, the reduction is directly proportional to the difference in production level (see Table VII-2). By comparison with the Base Case, the savings would range from about $3 billion to $4 billion at current world prices.

Each phase of the oil exploration-recovery process entails some economic effects. Preliminary exploratory drilling will have significant, though probably short-lived effects on employment in the area being explored. In the longer run, if exploration is successful, smaller but more permanent increases in employment could be expected, together with secondary increases in local economic activity as measured by retail sales or housing starts. Depending on the local availability of particular types of labor, the increased labor demand might be met either locally or from out-of-state workers moved into the production area.

Employment in oil production would grow under all of the options. On a national level, there would be very little difference between any pair of options. Locally, however, there could be significant differences, brought about by the large differences in tertiary production among the various options. These potential changes, masked by the larger conventional output in the aggregate, would occur within Regions 2, 5, and 6. In the case of alternatives involving options IIIA and IIIB, substantially greater $CO_2$-miscible production is expected, and extra employment opportunitites will develop in those areas where such extraction is feasible.

As noted earlier, differences in both domestic production and overall consumption of petroleum products among the pricing alternatives are very small. But compared to the Base Case, consumption of petroleum products will be slightly lower for each alternative (see Section VI.B). Shifts in patterns of consumption of the various petroleum products are not anticipated; rather a general shift to slightly lower consumption of all oil products between the Base Case and any alternative is likely. If national demand for energy is unaffected, then the lost consumption of petroleum products will be made up by increases in other fuels, most likely coal and nuclear energy. The trade-off in environmental impact depends on what mix of those two resources emerges. It is not possible in this analysis to estimate either the direction or magnitude of the change.

Refining operations are not likely to differ drastically between the Base Case and any of the alternatives. The product mix will be relatively the same with only slightly lower throughput.

Inland storage and transfer facilities would be much the same except that greater domestic production of crude under the alternatives might necessitate a marginally greater capacity and a slightly larger network of gathering lines. But this effect may not be realized (and certainly will not be important) because most of the marginal oil will be produced in existing fields where storage and transfer facilities exist. The effect of the pricing policies, then, will be to maintain and use these facilities for a longer period of time than might occur in the Base Case.

Production for micellar-polymer techniques is not expected to reach significant levels by 1979. Projects will have been started by that time, however, if the most propitious Stage III options are chosen (IIIA or IIIB). That choice could trigger significant changes in economic activity in industries concerned with supplying particular chemicals required by those technologies. The necessary expansion of industries supplying surfactants and other chemicals would probably result in increased chemical industry employment together with changes in the prices of these chemicals. Table VII-14 shows the chemical availability situation for

## TABLE VII-14

## AVAILABILITY OF CHEMICALS FOR TERTIARY OIL RECOVERY

| CHEMICAL | RAW MATERIALS | PROCESS | RECENT[a] PRICE $/lb | CURRENT SUPPLY $10^6$ lb/yr | USAGE RATE lb/bbl OIL PRODUCED | ESTIMATED DEMAND $10^6$ lb/yr | ESTIMATED DEMAND AS % CURR. SUPPLY | PHYSICAL FORM | COMMENTS ON AVAILABILITY |
|---|---|---|---|---|---|---|---|---|---|
| Polymers |  |  |  |  |  |  |  |  |  |
| Polyacrylamide (partially hydrolized) | Acrylonitrile<br>$H_2SO_4$ | Hydration w/sulfuric neutralization, ion-exchange, polymerization and hydrolysis (partial) | 1.50-2.00 | 50 | 1 | 210 | > 400 | Dry powder or liquid | Plant expansions likely to serve other growth markets (e.g. water treatment flocculants). Acrylonitrile feedstock capacity 1,[illegible] MM lbs/yr |
| Polysaccharide | Glucose + *Xanthomonas campestris* | Microbiological action | 2.50/lb | 40(E) |  |  | 500 | Powder | New plant capacity under construction should lead to significant price reduction |
| Surfactants |  |  |  |  |  |  |  |  |  |
| Linear alkylbenzene sulfonates | Kerosene<br>$C_{10}$-$C_{13}$ or $C_{11}$-$C_{14}$<br>$SO_3$, oleum<br>NaOH | Separation of straight-chain paraffins, alkylation, sulfonation, neutralization | .10-.20 lb. | 700-730 | 7-15 | 1470-3150 | 190-430 | Viscous liquid | Possible production at oil refineries and on-site to meet needs |
| Alcohols |  |  |  |  |  |  |  |  |  |
| Isopropanol | Refinery propylene<br>$H_2SO_4$ | Absorption in conc. $H_2SO_4$ hydrolysis of resulting isopropyl ester | .09/lb. | 2,500 | 2-8 | 420-1780 | 16-67 | Anhydrous liquid | Common alcohol, short-term shortages possible. Least expensive cosurfactant |
| Pentanol | Pentene | Hydration and acid | .18/lb. | NA |  |  | NA | Liquid/low viscosity |  |
| Hexanol | Hexene | Hydration and acid | .24/lb. | NA |  |  | NA | Liquid/low viscosity |  |
| n-Butanol | (1)crotonaldehyde from ethyl alcohol<br>(2)Propylene, CO, $H_2$ | Reduction by catalytic hydrogeneration<br>Oxo process - propylene to n-butyraldehyde, isobutyaldehyde | .16/lb. | 660 |  |  | 65-250 | Liquid | Possible use as substitute during shortage. |
| iso-Butanol | Propylene CO, $H_2$ | Oxo process (as above) | .16/lb. | 170 |  |  | 250-1,000 | Liquid |  |

[a] US Plant

each of the materials currently in bulk use for oil recovery. Comparison with 1985 levels indicates that expansion may be necessary in industries producing a number of those chemicals by that time.

### 6. Other Environmental Impacts

Many endangered species make their homes in the Gulf of Mexico and Southern California wetlands (see Tables VII-15 and VII-16). The California wetlands are rather limited in size by comparison to the Gulf Coast and the Atlantic Coast, so encroachments and pollution damage are particularly harmful. The Southern California coastal area is important for recreational hunting and fishing. Oil production lowers the value of the land for such activities, by displacing the wildlife and spoiling the natural beauty. Offshore oil production in all regions has been known to cause fouling of recreational beaches.

All of the pricing alternatives result in the same level of offshore production off the California coast (160,000 barrels per day). It is interesting to note that all, however, are below current (1975) production levels (220,000 barrels per day). Production along the Gulf Coast would be increased by all the options relative to both existing (1975) and 1979 Base Case projected levels.

The Gulf of Mexico is by far the most productive fishery region in the United States, with much of the activity concentrated near the Mississippi Delta in Louisiana. Landings in Texas and Louisiana in 1973-74 total nearly $200 million (see Appendix J). Estuarine-dependent species comprise 97.5 percent of the commercial fisheries catch. They are particularly vulnerable to pollution produced by river discharge and tidal action.

The coastal counties from Santa Barbara to San Diego are heavily urban, containing about half the population of California. Many petroleum extraction sites are located within Standard Metropolitan Statistical Areas, and extraction conflicts with urban and residential activities. The impact of petroleum production on other industries is relatively unimportant, with the possible exception of the fishing industry. Stephens[2] has shown dramatic decreases in the local waters' productivity of pelagic wetfish and tuna, the

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[2] J.R. Stephens, Jr., "Bay and Inshore Fish," in Proceedings of the Southern California Coastal Zone Symposium, Fullerton, Calif., March 17-18, 1972.

## TABLE VII-15

## SPECIES WITH RARE, ENDANGERED, OR PERIPHERAL STATUS IN THE GULF OF MEXICO

| SPECIES | STATUS | DISTRIBUTION |
|---|---|---|
| BROWN PELICAN | ENDANGERED | BREEDS ON ISLANDS ALONG GULF FROM FLORIDA TO TEXAS |
| FLORIDA GREAT WHITE HERON | RARE | BREEDS IN FLORIDA KEYS, FLORIDA BAY AND S. PENINSULA OF FLORIDA NORTH TO CAPE ROMANO |
| FLORIDA EVERGLADE KITE | ENDANGERED | FRESH WATER MARSHES OF SOUTHERN FLORIDA |
| SOUTHERN BALD EAGLE | ENDANGERED | NESTS IN ESTUARINE AREAS FROM FLORIDA TO TEXAS |
| ARCTIC PEREGRENE FALCON | ENDANGERED | IN MIGRATION ALONG THE BEACHES OF OUTER GULF COAST ISLANDS |
| ATTWATER'S GREATER PRAIRIE CHICKEN | ENDANGERED | DISJUNCT POPULATIONS IN TEXAS |
| CAPE SABLE SPARROW | ENDANGERED | FRESH AND BRACKISH WATER MARSHES IN SOUTHWESTERN FLORIDA. |
| AMERICAN ALLIGATOR | ENDANGERED | MISSISSIPPI WEST TO CORPUS CHRISTI, TEXAS |
| AMERICAN CROCODILE | PERIPHERAL | S. FLORIDA AND FLORIDA KEYS |
| GREEN TURTLE | PERIPHERAL | GULF COAST WATER - PRESENT DURING SUMMER. MAY NEST ON FLORIDA COAST |
| RED WOLF | ENDANGERED | SOUTHEASTERN TEXAS AND SOUTHWESTERN LOUISIANA |
| FLORIDA MANATEE | ENDANGERED | COASTAL AREAS OF FLORIDA |

TABLE VII-15 (CONT.)

| SPECIES | STATUS | DISTRIBUTION |
|---|---|---|
| WHOOPING CRANE | ENDANGERED | WINTERS AT ARANSES NATIONAL WILDLIFE REFUGE, TEXAS AND NEARBY GULF COAST ISLANDS |
| FLORIDA SANDHILL CRANE | RARE | WEST PRAIRIES OF PENINSULAR FLORIDA AND SOUTHERN MISSISSIPPI |
| ESKIMO CURLEW | ENDANGERED | SPRING MIGRANTS ON TEXAS COAST |
| AMERICAN IVORY BILLED WOODPECKER | ENDANGERED | SOUTHEAST TEXAS |
| RED COCKADED WOODPECKER | ENDANGERED | OPEN, OLD PINE WOODLANDS IN GULF COAST REGION - FLORIDA TO EASTERN TEXAS |
| FLORIDA PANTHER | ENDANGERED | FOUR COUNTIES IN FLORIDA |
| KEY DEER | ENDANGERED | KEY DEER NATIONAL WILDLIFE REFUGE, FLORIDA |
| HOUSTON TOAD | ENDANGERED | LOBLOLLY PINE, HOUSTON TEXAS |

Source: William F. Gusey, Petroleum Production and Fish and Wildlife Resources, The Gulf of Mexico, Cook Inlet, Alasks, Santa Barbara Channel, California, Appendix 6.

## TABLE VII-16

## ENDANGERED SPECIES OF CALIFORNIA

California Brown Pelican (*Pelecanus occidentalis californicus*)
Southern Bald Eagle (*Haliaeetus leucocephalus*)
California Condor (*Gymnogyps californianus*)
American Peregrine Falcon (*Falco peregrinus anatum*)
Light-Footed Clapper Rail (*Rallus longirostris levyses*)
California Least Tern (*Sterna albifrons browni*)
Belding's Savannah Sparrow (*Passerculus sandwichensis beldingi*)
Unarmored Threespine Stickleback (*Gastervsteus aculeatus williamsoni*)

Gray Whale (*Eschrichtius gibbosus*)
Blue Whale (*Balenoptera musculus*)
Finback Whale (*Balenoptera physalus*)
Sei Whale (*Balenoptera borealis*)
Humpback Whale (*Megaptera movreangliae*)
Pacific Right Whale (*Balena galcialis*)
Sperm Whale (*Physterer catodon*)

## RARE SPECIES

Island Fox (*Urocyon lattorallis*)
Guadalupe Fur Seal (*Arctocephalus philippii townsend*)
California Black Rail (*Laterallus samarcensis coturniculus*)

two most important commercial fish. The pollution and reduction of habitat caused by oil extraction is probably swamped by the presence of 10 million people, but nevertheless may have contributed to the loss.

### 7. Offshore Oil Spills

Offshore oil spills arise from both production and also transport in tankers. Tankers are used to land imported crude oil and petroleum products and for coastal transit of crude and petroleum products in U.S. waters, mainly from Gulf Coast ports to East Coast ports. The environmental impact of the various options was estimated through an analysis of expected magnitude of spills from both sources. Three cases are considered, corresponding to the cases used in the analysis of price-induced demand changes (Chapter VI). Production and import quantities corresponding to these cases are given in Table VII-17.

The regional import figures in Table VII-17 are obtained by apportioning the net national difference between increased production and decreased imports among the three coastal areas according to the fraction of total U.S. imports each received in 1974 (Table VII-18).

Estimates of oil spill risk (in barrels per day) in the Gulf Coast are obtained by adding the quantitites due to transport and due to production. Transport amounts are the sum of imports plus coastal traffic out. Coastal traffic out is assumed to be the net difference of production less that which leaves the region by pipeline (about 2.9 million barrels per day). Spills due to transport are estimated by applying a factor of 35.5 barrels per million barrels transported.[3] Similarly, production spills are based on a factor of 140 barrels spilled per million barrels produced.[4] The results of the analysis are given in Table VII-19.

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[3] B.L. Walton et al., Draft Environmental Impact Assessment of Adjustments to Domestic Crude Oil Prices Under the Second Stage of the Energy Policy and Conservation Act, Stanford Research Institute, May 1976, p. 28.

[4] Richard D. Wilson, "Estimate of Annual Input of Petroleum to the Marine Environment from Offshore Production Operations," in Background Papers for a Workshop on Inputs, Fates, and Effects of Petroleum in the Marine Environment, Vol. I, Ocean Affairs Board, National Academy of Sciences, Washington, D.C., 1973.

## TABLE VII-17

## REGIONAL PRODUCTION AND IMPORTS, 1979[1]

| | TOTAL U.S. | | CALIFORNIA (2 & 2A) | | GULF COAST | | EAST COAST (8,9,10,11,11A) | |
|---|---|---|---|---|---|---|---|---|
| | PRODUCTION | IMPORTS | PRODUCTION | IMPORTS | PRODUCTION | IMPORTS | PRODUCTION | IMPORTS |
| BASE CASE | 9.75 | 7.55 | 1.08 | 1.18 | 3.98 | 1.98 | 0.32 | 4.19 |
| LOW I & II[2] | 10.42 | 6.39 | 1.24 | 0.96 | 4.36 | 1.50 | 0.37 | 3.93 |
| HIGH II & III[3] | 10.48 | 6.30 | 1.24 | 0.94 | 4.34 | 1.49 | 0.37 | 3.87 |

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[1] Production figures from Chapter VI.

[2] Low figures are averages for Cases IIA, IIC, IIA-IIIA, IIC-IIIA, IIC-IIIB.

[3] High figures are averages for Cases IIA-IIIB, IIA-IIID, IIB-IIID, IIC-IIID.

### TABLE VII-18

### 1974 IMPORTS
($10^6$ barrels)

| REGION | CRUDE | PRODUCTS | TOTAL | PERCENT OF GRAND TOTAL |
|---|---|---|---|---|
| EAST COAST | 515 | 600 | 1,115 | 57 |
| CALIFORNIA | 390 | 145 | 535 | 27 |
| GULF | 215 | 100 | 315 | 16 |
| TOTAL | 1,120 | 845 | 1,965 | |

## TABLE VII-19

## SPILL POTENTIAL IN GULF COAST

| | IMPORTS AND PRODUCTION ($10^6$ bbl/day) | IMPORTS AND TRAFFIC OUT ($10^6$ bbl/day) | SPILL POTENTIAL FROM TRANSPORT (bbl/day) | SPILLS FROM PRODUCTION (bbl/day) |
|---|---|---|---|---|
| BASE | 5.96 | 5.04 | 179 | 192 |
| LOW | 5.86 | 4.46 | 158 | 198 |
| HIGH | 1.83 | 4.42 | 157 | 198 |

Both the high and low cases would result in reductions of spill risk over the Base Case, about 4 percent for the low price options and about 5 percent for the high price options. The difference between options (about 1 barrel per day) is insignificant in terms of the precision of the analysis.

Spills along the East Coast are due entirely to transport as none of the options induce production through 1979. Shipments landed in East Coast ports are estimated by subtracting quantities pipelined (about 1.92 million barrels per day) into the regions supplied from coastal ports (8, 9, 10, and 11) from demand in these regions. These regions consume about 41 percent of total U.S. consumption. The results are given in Table VII-20. Both sets of options reduce the risk over the Base Case by about 2.5 percent.

Results for a similar analysis for the Northeast Coast (Maine to Maryland) are shown in Table VII-21.

In general, reduced imports are offset by increased coastal traffic. U.S ships and crews (coastal transit) are known to have a better spill record than do foreign ships (imports). On the other hand, coastal traffic remains in U.S. coastal waters for longer periods of time per barrel landed. In the absence of data on each mode, the same factor (35.5 barrels per million barrels) was used uniformly.

### 8. Relative Contributions of Production-Based Emissions to Total Energy Related Activities

The discussion of environmental impact presented above highlights the direct effects due to production and the closely-related transportation sector. Regional differences are discussed and in several cases appear quite large. To provide additional perspective it is valuable to examine the impact of petroleum production related activities to overall energy consumption.

The methodology outlined in Section III.D was used for such an overall analysis. A model developed to generate environmental residuals for Project Independence was used as the computational framework.[5] Primary inputs to this model are estimates of energy production, transportation, conversion,

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[5] Energy Resources Company Inc., Assessment of Environmental Implications of Project Independence, for the U.S. Environmental Protection Agency, 1975.

## TABLE VII-20

## EAST COAST SPILL POTENTIAL

| | DEMAND ($10^6$ bbl/day) | WATER TRANSPORT ($10^6$ bbl/day) | SPILL (bbl/day) |
|---|---|---|---|
| BASE | 7.71 | 5.79 | 206 |
| LOW | 7.58 | 5.66 | 201 |
| HIGH | 7.57 | 5.65 | 201 |

## TABLE VII-21

## NORTHEAST COAST SPILL POTENTIAL

| | DEMAND ($10^6$ bbl/day) | WATER TRANSPORT ($10^6$ bbl/day) | SPILL POTENTIAL (bbl/day) |
|---|---|---|---|
| BASE | 5.06 | 4.24 | 151 |
| LOW | 4.97 | 4.15 | 147 |
| HIGH | 4.96 | 4.14 | 147 |

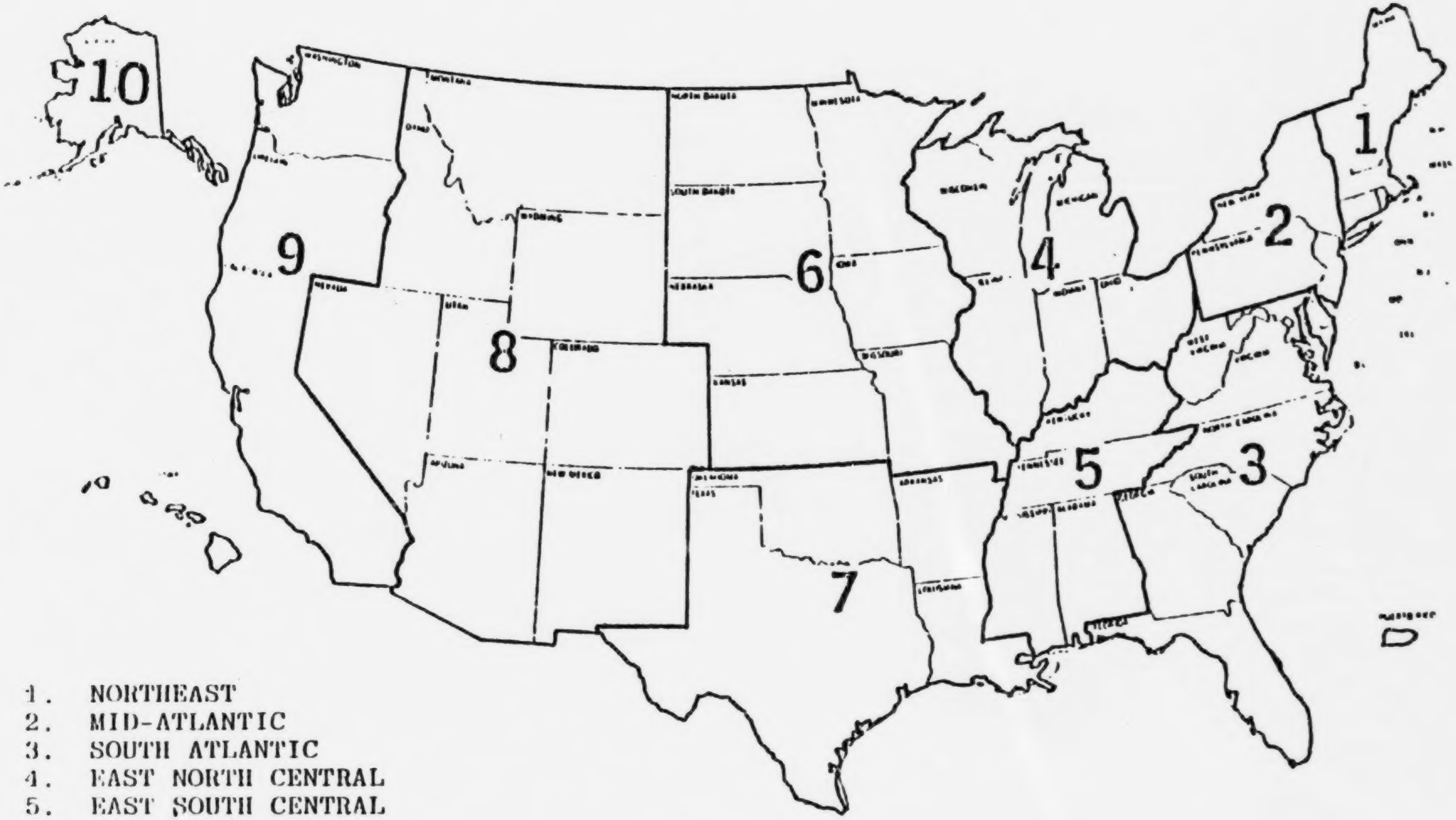
and consumption by Demand Regions, as defined in conjunction with Project Independence (See Figure VII-1). Inputs are provided for the three major fossil fuels, petroleum, natural gas, and coal, as well as nuclear, hydropower and geothermal. The basis for estimating consumption is detailed in Section III.D. Tables giving the breakdown among the various fuel sectors are presented there.

Residuals of principal air and water pollutants are generated as output by applying a set of coefficients to the energy flows. The output set of residuals corresponding to the 1979 set of scenarios is shown in Table VII-22. Data are given for organics in water and air pollutants including particulates, nitrogen oxides, sulfur dioxide, hydrocarbons, and carbon monoxide. The data presented in this table are not directly comparable to the data in the preceding tables in this chapter, which are tabulated according to Production Regions (See Figure VI-1). This discrepancy, resulting from the use of different models to generate production and consumption estimates, does not interfere with the significance and utility of the data.

It is readily apparent that, with only a few exceptions, no difference exists between scenarios. The residual estimates are identical to two (and often more than two) significant figures. Only the first two figures are meaningful. The remaining figures result from the computer output format which was used directly in preparing the table.

Regional differences due to production are completely overwhelmed by residuals generated in the conversion and consumption sectors. Only in organics (in water) and in sulfur oxides generation can any meaningful differences be discerned. Only Demand Region 9, which corresponds exactly to the combination of Production Regions 2 and 2a, that is, west coast onshore and offshore production, shows differences. These differences can be attributed to variations in steam injection based production. The higher levels of sulfur dioxide correspond to the scenarios discussed above (see Table VII-8).

Not only are the scenario-to-scenario differences very slight or absent, but the relative contributions of petroleum production-based emissions to overall residuals generation is also very small. For example, the national total organics loading due to production (1979 Base Case) is 64.7 tons per day; the corresponding national total for all energy utilization is 238 tons per day. Similarly, for sulfur oxide generation, emissions are 185.3 tons per day for production compared to over 132,000 tons per day.



1. NORTHEAST
2. MID-ATLANTIC
3. SOUTH ATLANTIC
4. EAST NORTH CENTRAL
5. EAST SOUTH CENTRAL
6. WEST NORTH CENTRAL
7. WEST SOUTH CENTRAL
8. MOUNTAIN
9. PACIFIC
10. ALASKA

Figure VII-1. Demand Regions

# TABLE VII-22

## COMPARISON OF TOTAL POLLUTION LOADINGS BY DEMAND REGION FOR EACH ALTERNATIVE

ORGANICS (100 TONS/DAY)

| DR* | BC | IIA | IIB | IIC | IIA IIIA | IIB IIIA | IIC IIIA | IIA IIIB | IIB IIIB | IIC IIIB | IIA IIIC | IIB IIIC | IIC IIIC | IIA IIIC | IIB IIIC | IIC IIIC |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 0.006 | 0.006 | 0.006 | 0.006 | 0.006 | 0.006 | 0.006 | 0.006 | 0.005 | 0.006 | 0.006 | 0.006 | 0.006 | 0.006 | 0.005 | 0.006 |
| 2 | 0.050 | 0.050 | 0.050 | 0.050 | 0.050 | 0.050 | 0.050 | 0.050 | 0.050 | 0.050 | 0.050 | 0.050 | 0.050 | 0.050 | 0.050 | 0.050 |
| 3 | 0.132 | 0.133 | 0.133 | 0.133 | 0.132 | 0.132 | 0.133 | 0.132 | 0.132 | 0.132 | 0.133 | 0.133 | 0.133 | 0.133 | 0.133 | 0.133 |
| 4 | 0.147 | 0.148 | 0.148 | 0.148 | 0.148 | 0.148 | 0.148 | 0.148 | 0.148 | 0.148 | 0.148 | 0.148 | 0.148 | 0.148 | 0.148 | 0.148 |
| 5 | 0.061 | 0.062 | 0.062 | 0.062 | 0.062 | 0.062 | 0.062 | 0.062 | 0.062 | 0.062 | 0.062 | 0.062 | 0.062 | 0.062 | 0.062 | 0.062 |
| 6 | 0.055 | 0.056 | 0.056 | 0.056 | 0.055 | 0.055 | 0.056 | 0.055 | 0.055 | 0.055 | 0.056 | 0.056 | 0.056 | 0.056 | 0.056 | 0.056 |
| 7 | 0.558 | 0.579 | 0.579 | 0.578 | 0.577 | 0.576 | 0.582 | 0.573 | 0.567 | 0.578 | 0.586 | 0.586 | 0.585 | 0.586 | 0.586 | 0.585 |
| 8 | 0.057 | 0.057 | 0.057 | 0.059 | 0.057 | 0.059 | 0.059 | 0.059 | 0.059 | 0.059 | 0.059 | 0.059 | 0.059 | 0.057 | 0.057 | 0.059 |
| 9 | 0.101 | 0.120 | 0.121 | 0.119 | 0.122 | 0.122 | 0.122 | 0.122 | 0.122 | 0.122 | 0.120 | 0.121 | 0.119 | 0.120 | 0.121 | 0.119 |
| 10 | 0.073 | 0.073 | 0.073 | 0.073 | 0.073 | 0.073 | 0.073 | 0.073 | 0.073 | 0.073 | 0.073 | 0.073 | 0.073 | 0.073 | 0.073 | 0.073 |
| 11 | 1.280 | 1.285 | 1.286 | 1.293 | 1.285 | 1.283 | 1.290 | 1.281 | 1.277 | 1.287 | 1.293 | 1.293 | 1.290 | 1.293 | 1.293 | 1.290 |

PARTICULATES (TONS/DAY)

| DR* | BC | IIA | IIB | IIC | IIA IIIA | IIB IIIA | IIC IIIA | IIA IIIB | IIB IIIB | IIC IIIB | IIA IIIC | IIB IIIC | IIC IIIC | IIA IIIC | IIB IIIC | IIC IIIC |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 375 | 375 | 375 | 375 | 375 | 375 | 375 | 375 | 375 | 375 | 375 | 375 | 375 | 375 | 375 | 375 |
| 2 | 1810 | 1810 | 1810 | 1810 | 1810 | 1810 | 1810 | 1810 | 1810 | 1810 | 1810 | 1810 | 1810 | 1810 | 1810 | 1810 |
| 3 | 1504 | 1504 | 1509 | 1504 | 1509 | 1509 | 1504 | 1504 | 1504 | 1504 | 1504 | 1509 | 1504 | 1504 | 1504 | 1509 |
| 4 | 2239 | 2239 | 2239 | 2239 | 2239 | 2239 | 2239 | 2239 | 2239 | 2239 | 2239 | 2239 | 2239 | 2239 | 2239 | 2239 |
| 5 | 900 | 900 | 900 | 900 | 900 | 900 | 900 | 900 | 900 | 900 | 900 | 900 | 900 | 900 | 900 | 900 |
| 6 | 678 | 678 | 678 | 678 | 678 | 678 | 678 | 678 | 678 | 678 | 678 | 678 | 678 | 678 | 678 | 678 |
| 7 | 690 | 690 | 690 | 690 | 690 | 690 | 690 | 690 | 690 | 690 | 690 | 690 | 690 | 690 | 690 | 690 |
| 8 | 315 | 315 | 315 | 315 | 315 | 315 | 315 | 315 | 315 | 315 | 315 | 315 | 315 | 315 | 315 | 315 |
| 9 | 918 | 918 | 919 | 918 | 921 | 921 | 921 | 921 | 921 | 921 | 918 | 919 | 918 | 918 | 919 | 918 |
| 10 | 24 | 24 | 24 | 24 | 24 | 24 | 24 | 24 | 24 | 24 | 24 | 24 | 24 | 24 | 24 | 24 |
| 11 | 9057 | 9057 | 9058 | 9057 | 9060 | 9060 | 9060 | 9060 | 9060 | 9060 | 9057 | 9058 | 9057 | 9057 | 9058 | 9057 |

NO(X) (TONS/DAY)

| DR* | BC | IIA | IIB | IIC | IIA IIIA | IIB IIIA | IIC IIIA | IIA IIIB | IIB IIIB | IIC IIIB | IIA IIIC | IIB IIIC | IIC IIIC | IIA IIIC | IIB IIIC | IIC IIIC |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 1833 | 1833 | 1833 | 1833 | 1833 | 1833 | 1833 | 1833 | 1833 | 1833 | 1833 | 1833 | 1833 | 1833 | 1833 | 1833 |
| 2 | 8200 | 8200 | 8200 | 8200 | 8200 | 8200 | 8200 | 8200 | 8200 | 8200 | 8200 | 8200 | 8200 | 8200 | 8200 | 8200 |
| 3 | 10439 | 10439 | 10439 | 10439 | 10439 | 10439 | 10439 | 10439 | 10439 | 10439 | 10439 | 10439 | 10439 | 10439 | 10439 | 10439 |
| 4 | 13238 | 13238 | 13238 | 13238 | 13238 | 13238 | 13238 | 13238 | 13238 | 13238 | 13238 | 13238 | 13238 | 13238 | 13238 | 13238 |
| 5 | 5858 | 5858 | 5858 | 5858 | 5858 | 5858 | 5858 | 5858 | 5858 | 5858 | 5858 | 5858 | 5858 | 5858 | 5858 | 5858 |
| 6 | 5300 | 5300 | 5300 | 5300 | 5300 | 5300 | 5300 | 5300 | 5300 | 5300 | 5300 | 5300 | 5300 | 5300 | 5300 | 5300 |
| 7 | 7752 | 7752 | 7752 | 7752 | 7752 | 7752 | 7752 | 7752 | 7752 | 7752 | 7752 | 7752 | 7752 | 7752 | 7752 | 7752 |
| 8 | 3593 | 3593 | 3593 | 3593 | 3593 | 3593 | 3593 | 3593 | 3593 | 3593 | 3593 | 3593 | 3593 | 3593 | 3593 | 3593 |
| 9 | 4460 | 4460 | 4465 | 4460 | 4479 | 4479 | 4479 | 4479 | 4479 | 4479 | 4460 | 4465 | 4460 | 4460 | 4465 | 4460 |
| 10 | 109 | 109 | 109 | 109 | 109 | 109 | 109 | 109 | 109 | 109 | 109 | 109 | 109 | 109 | 109 | 109 |
| 11 | 60787 | 60787 | 60792 | 60787 | 60807 | 60807 | 60807 | 60807 | 60807 | 60807 | 60787 | 60792 | 60787 | 60787 | 60792 | 60787 |

SO(X) (TONS/DAY)

| DR* | BC | IIA | IIB | IIC | IIA IIIA | IIB IIIA | IIC IIIA | IIA IIIB | IIB IIIB | IIC IIIB | IIA IIIC | IIB IIIC | IIC IIIC | IIA IIIC | IIB IIIC | IIC IIIC |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 2029 | 2029 | 2029 | 2029 | 2029 | 2029 | 2029 | 2029 | 2029 | 2029 | 2029 | 2029 | 2029 | 2029 | 2029 | 2029 |
| 2 | 11178 | 11178 | 11178 | 11178 | 11178 | 11178 | 11178 | 11178 | 11178 | 11178 | 11178 | 11178 | 11178 | 11178 | 11178 | 11178 |
| 3 | 11634 | 11634 | 11634 | 11634 | 11634 | 11634 | 11634 | 11634 | 11634 | 11634 | 11634 | 11634 | 11634 | 11634 | 11634 | 11634 |
| 4 | 21974 | 21974 | 21974 | 21974 | 21974 | 21974 | 21974 | 21974 | 21974 | 21974 | 21974 | 21974 | 21974 | 21974 | 21974 | 21974 |
| 5 | 7256 | 7256 | 7256 | 7256 | 7256 | 7256 | 7256 | 7256 | 7256 | 7256 | 7256 | 7256 | 7256 | 7256 | 7256 | 7256 |
| 6 | 7005 | 7005 | 7005 | 7005 | 7005 | 7005 | 7005 | 7005 | 7005 | 7005 | 7005 | 7005 | 7005 | 7005 | 7005 | 7005 |
| 7 | 1912 | 1912 | 1912 | 1912 | 1912 | 1912 | 1912 | 1912 | 1912 | 1912 | 1912 | 1912 | 1912 | 1912 | 1912 | 1912 |
| 8 | 1488 | 1488 | 1488 | 1488 | 1488 | 1488 | 1488 | 1488 | 1488 | 1488 | 1488 | 1488 | 1488 | 1488 | 1488 | 1488 |
| 9 | 1766 | 1766 | 1777 | 1766 | 1809 | 1809 | 1809 | 1809 | 1809 | 1809 | 1766 | 1777 | 1766 | 1766 | 1777 | 1766 |
| 10 | 24 | 24 | 24 | 24 | 24 | 24 | 24 | 24 | 24 | 24 | 24 | 24 | 24 | 24 | 24 | 24 |
| 11 | 66270 | 66270 | 66281 | 66270 | 66314 | 66314 | 66314 | 66314 | 66314 | 66314 | 66270 | 66281 | 66270 | 66270 | 66281 | 66270 |

*DEMAND REGION INDEX

1) North East
2) Mid-Atlantic
3) South-Atlantic
4) East North Central
5) East South Central
6) West North Central
7) West South Central
8) Mountain
9) Pacific
10) Alaska
11) National Total

# TABLE VII-22 (CONT.)

HYDROCARBONS (TONS/DAY)

| DR* | BC | IIA | IIB | IIC | IIA<br>IIIA | IIB<br>IIIA | IIC<br>IIIA | IIA<br>IIIB | IIB<br>IIIB | IIC<br>IIIB | IIA<br>IIIC | IIB<br>IIIC | IIC<br>IIIC | IIA<br>IIIC | IIB<br>IIIC | IIC<br>IIIC |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 786 | 786 | 786 | 786 | 786 | 786 | 786 | 786 | 786 | 786 | 786 | 786 | 786 | 786 | 786 | 786 |
| 2 | 2333 | 2333 | 2333 | 2333 | 2333 | 2333 | 2333 | 2333 | 2333 | 2333 | 2333 | 2333 | 2333 | 2333 | 2333 | 2333 |
| 3 | 2773 | 2773 | 2773 | 2773 | 2773 | 2773 | 2773 | 2773 | 2773 | 2773 | 2773 | 2773 | 2773 | 2773 | 2773 | 2773 |
| 4 | 3506 | 3506 | 3506 | 3506 | 3506 | 3506 | 3506 | 3506 | 3506 | 3506 | 3506 | 3506 | 3506 | 3506 | 3506 | 3506 |
| 5 | 1297 | 1297 | 1297 | 1297 | 1297 | 1297 | 1297 | 1297 | 1297 | 1297 | 1297 | 1297 | 1297 | 1297 | 1297 | 1297 |
| 6 | 2435 | 2435 | 2435 | 2435 | 2435 | 2435 | 2435 | 2435 | 2435 | 2435 | 2435 | 2435 | 2435 | 2435 | 2435 | 2435 |
| 7 | 14121 | 14134 | 14134 | 14121 | 14146 | 14146 | 14146 | 14146 | 14146 | 14146 | 14134 | 14134 | 14121 | 14134 | 14134 | 14121 |
| 8 | 2111 | 2111 | 2111 | 2111 | 2111 | 2111 | 2111 | 2111 | 2111 | 2111 | 2111 | 2111 | 2111 | 2111 | 2111 | 2111 |
| 9 | 3435 | 3460 | 3460 | 3435 | 3473 | 3473 | 3473 | 3473 | 3473 | 3473 | 3460 | 3460 | 3435 | 3460 | 3460 | 3435 |
| 10 | 60 | 60 | 60 | 60 | 60 | 60 | 60 | 60 | 60 | 60 | 60 | 60 | 60 | 60 | 60 | 60 |
| 11 | 32559 | 32597 | 32597 | 32559 | 32923 | 32923 | 32923 | 32923 | 32923 | 32923 | 32897 | 32897 | 32859 | 32897 | 32897 | 32859 |

CARBON MONOXIDE (TONS/DAY)

| DR* | BC | IIA | IIB | IIC | IIA<br>IIIA | IIB<br>IIIA | IIC<br>IIIA | IIA<br>IIIB | IIB<br>IIIB | IIC<br>IIIB | IIA<br>IIIC | IIB<br>IIIC | IIC<br>IIIC | IIA<br>IIIC | IIB<br>IIIC | IIC<br>IIIC |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 5744 | 5744 | 5744 | 5744 | 5744 | 5744 | 5744 | 5744 | 5744 | 5744 | 5744 | 5744 | 5744 | 5744 | 5744 | 5744 |
| 2 | 16617 | 16617 | 16617 | 16617 | 16617 | 16617 | 16617 | 16617 | 16617 | 16617 | 16617 | 16617 | 16617 | 16617 | 16617 | 16617 |
| 3 | 17031 | 17031 | 17031 | 17031 | 17031 | 17031 | 17031 | 17031 | 17031 | 17031 | 17031 | 17031 | 17031 | 17031 | 17031 | 17031 |
| 4 | 21055 | 21055 | 21055 | 21055 | 21055 | 21055 | 21055 | 21055 | 21055 | 21055 | 21055 | 21055 | 21055 | 21055 | 21055 | 21055 |
| 5 | 8252 | 8252 | 8252 | 8252 | 8252 | 8252 | 8252 | 8252 | 8252 | 8252 | 8252 | 8252 | 8252 | 8252 | 8252 | 8252 |
| 6 | 9335 | 9335 | 9336 | 9335 | 9336 | 9336 | 9335 | 9335 | 9336 | 9336 | 9336 | 9336 | 9336 | 9336 | 9336 | 9336 |
| 7 | 12083 | 12146 | 12146 | 12083 | 12208 | 12208 | 12208 | 12208 | 12208 | 12208 | 12146 | 12146 | 12083 | 12146 | 12146 | 12083 |
| 8 | 6150 | 6150 | 6150 | 6150 | 6150 | 6150 | 6150 | 6150 | 6150 | 6150 | 6150 | 6150 | 6150 | 6150 | 6150 | 6150 |
| 9 | 19274 | 19419 | 19419 | 19274 | 19482 | 19482 | 19482 | 19482 | 19482 | 19482 | 19419 | 19419 | 19274 | 19419 | 19419 | 19274 |
| 10 | 322 | 322 | 322 | 322 | 322 | 322 | 322 | 322 | 322 | 322 | 322 | 322 | 322 | 322 | 322 | 322 |
| 11 | 115890 | 116077 | 116077 | 115890 | 116202 | 116202 | 116202 | 116202 | 116202 | 116202 | 116077 | 116077 | 115890 | 116077 | 116077 | 115890 |

*DEMAND REGION INDEX

1) North East
2) Mid-Atlantic
3) South-Atlantic
4) East North Central
5) East South Central
6) West North Central
7) West South Central
8) Mountain
9) Pacific
10) Alaska
11) National Total

## B. 1985 Case

### 1. Domestic Oil Production

Petroleum production in 1985 is substantially independent of the pricing policies in effect until 1979 (see Chapter III). All effects of the various pricing alternatives, in essence, vanish because of the effects of decontrol of oil prices in 1979; production levels in 1985 do not depend on the alternative chosen. Production in 1985 is estimated to total 12,210 thousand barrels per day, 3,830 thousand barrels per day above the 1975 level. This represents a 45.7 percent increase in production. Two regions comprise 98.7 percent of the increase -- 41.5 percent from California, and 57.2 percent from Alaska.

Conventional onshore production contributes the largest portion (1,815 thousand barrels per day) of the increase, primarily due to North Slope production. Offshore development increases 1,130 thousand barrels per day, and the remaining difference of 885 thousand barrels per day comes from increases in tertiary projects, principally steam methods.

In 1975 the Gulf Coast regions accounted for 65.9 percent of total domestic production. Although production for the region increases by 1 percent in 1985, this area's contribution to domestic production drops to 45.7 percent of the total. A 14.7 percent decrease in onshore production is offset by a 43 percent increase in offshore production.

Total production in Region 2 increases by 178.6 percent by 1985. Onshore development comprises 39.6 percent of the 1,590 thousand barrel per day increase, 26.4 percent from offshore development, and 25.1 percent from steam-recovery projects. The remaining 8.8 percent is contributed by $CO_2$ injection and in-situ combustion projects. The regional increase accounts for 41.5 percent of the total national production increase.

By 1985, the Alaska regions will be producing 2,380 thousand barrels of oil per day. The great bulk of new production is from the onshore fields on the Alaskan North Slope, which are expected to yield 2.05 million barrels of oil per day, 86.1 percent of Alaskan oil production and 53.5 percent of the total increase in national production. The remaining 330 thousand barrels per day will be produced from offshore fields.

## 2. Environmental Impacts

In general, the various environmental residuals resulting from oil production are expected to increase over their 1975 levels by 1985 (see Tables C-18 and C-36). Organics will increase by 65 percent to 92.2 tons per day. About half of the amount will be generated in the Gulf Coast states, 24 percent in Region 2, and 6 percent in Alaska's North Slope. Ninety-eight percent of environmental residuals due to steam-recovery methods -- PM, $NO_x$, and $SO_x$ -- will come from tertiary recovery projects in California. These residuals are expected to increase by about 225 percent. Hydrocarbon and carbon monoxide residuals will increase 25-fold and 35-fold, respectively, by 1985.

The effect of the various policies on the environment during the period of 1979 to 1985 may differ according to the starting point defined by 1979 production levels. Nevertheless, the different impacts associated with the 1979 alternatives are small and, due to the converging tendencies of the alternatives, may be expected to be smaller in each succeeding year.

# CHAPTER VIII

## MITIGATING MEASURES

The environmental impacts of oil development on the scale stimulated by the oil pricing policies are in general not severe. Only in a few localized areas are there likely to be impacts that may cause concern. These potential impacts include consumption of freshwater supplies, air pollution from thermal recovery processes, groundwater pollution from reinjected brines, degradation of aesthetic characteristics, and contamination resulting from oil spills. In every case, control measures would be applied sufficient to meet environmental control regulations.

Beyond those measures which are mandated by regulation, it is possible to apply means to mitigate the potential environmental impacts either by reducing the likelihood or severity of their occurrence or by applying remedial measures. Following are several possible measures that could be applied to mitigate the above mentioned environmental consequences of production effects of price regulations:

1. As a general measure, conservation and reduction of demand for petroleum products would lower the overall production and/or importation of crude oil and would lessen the likelihood of all the potential impacts.

2. Produced waters may be recycled and salt water may be obtained to minimize the use of freshwater. In general, local water supplies need not be depleted or diverted from other uses if sites are chosen carefully and the water is used efficiently. In most cases the water is reused forming a self-contained, constantly recirculating system. Most of it is obtained from the well's accumulated produced water instead of from local groundwater sources. Due to inevitable losses, the addition of makeup water is sometimes necessary. It is usually possible, however, to obtain this from non-freshwater sources as well, such as saline aquifers.

3. In steam injection, new boiler design and chemical treatment may make it possible to produce steam from saline water without damaging the boiler, reducing freshwater demands.

4. Reinjection of the brine not only helps to meet water supply needs, it also mitigates the brine disposal problem. Injected water may contain dissolved hydrocarbons and toxic heavy metals, thereby posing potential threats to groundwater supplies. Reusing this water reduces the amounts of chemicals that potentially enter ground water.

5. It is conceivable that the trace materials in produced waters could be chemically treated, recovered and reapplied elsewhere. Recycling industries and "waste exchanges" are only now beginning to emerge. Stricter Federal regulation of wastewater disposal, and wider interpretation of PL 92-500 (the Federal Water Pollution Control Act Amendments of 1972) to subsidize control of toxic substances at their sources, would assure such industries a predictable market.

6. Air emissions from oil production operations must be controlled to conform to all appropriate emission regulations. Many single facilities are, however, smaller than the minimum size to which the regulations apply. Emissions from these sites can be lessened by employing technological controls even in the absence of specific regulations. Hydrocarbon emissions from conventional and advanced recovery operations, particularly thermal methods, can be controlled by employing one of several techniques: adsorption, scrubbing, afterburning, etc. Recovery of hydrocarbons would offset some of the cost of emissions control. Good housekeeping practises can also help to eliminate fugitive hydrocarbon emissions from leaky valves, gaskets, seals, etc. Scrubbers or use of low-sulfur fuel can reduce $SO_2$ emissions from steam recovery sites.

7. The use of electrical motors can minimize the air pollution problem presented by pumps and compressors.

8. Adverse aesthetic effects can be minimized by such techniques as placing operations in buildings (currently practiced on Long Beach), putting fences and trees around facilities and burying pipelines.

9. Emergency spill plans and good housekeeping practises at production sites can both lessen the probability of spills in the first place and also minimize the impact if spills do occur.

10. Improved standards for tankers and stronger enforcement of existing regulations can reduce the probability of spills at sea.

## CHAPTER IX

## ADVERSE ENVIRONMENTAL IMPACTS WHICH CANNOT BE AVOIDED

Oil exploration and production have well-known and fairly well-defined environmental impacts as described earlier. Even after applying those control measures required by regulation and using other reasonable methods to mitigate the impacts still to be felt, there remain adverse environmental impacts which cannot be avoided. Most are chronic with low-level effects, but some are rare events with potentially more serious consequences. Almost all are local in nature.

1. In spite of all control efforts there will be atmospheric emissions at production sites. The emissions caused by oil production are not expected to be high and can be reduced significantly with appropriate control measures, but nevertheless will not totally be eliminated. Low levels of fugitive hydrocarbon emissions from oil handling processes cannot be avoided entirely either.

2. The steam injection process requires large quantities of freshwater. As discussed in Section VII.A.3, this is not expected to be a major problem, but unless techniques are developed to produce steam from salt water without damaging boilers, the use of freshwater is unavoidable.

3. Water supplies can become contaminated with oil or materials in injected waters from spills, well failures, and changes in the oil-bearing formation. Because water used in crude oil production must meet stringent standards (to prevent corrosion, for example), such waters must usually be treated before, as well as after extraction of the oil. Chemical agents are frequently added to the process water in order to prevent corrosion and slime accumulation, and these agents -- many of them toxic -- then become part of the wastewater. Unless the injection of this water proceeds carefully, contamination of ground and surface waters can result.

4. Other environmental impacts of oil recovery that are unavoidable in some cases include: noise, surface disturbances and alterations in land use, subsidence, degradation of aesthetic values ("visual impact"), and changes in local plant and animal life. It is also possible that damage to recreational, historical or archeological sites may occur.

5. The very nature of oil spills and the consequent environmental impact lead to unavoidable adverse effects. In spite of improvements in housekeeping practices at production and pipeline facilities and improvement in tanker design and operations, spills are bound to occur. The environmental aftermath of spills is highly variable and unpredictable. The immediate catastrophic impact of the Argo Merchant spill expected by many did not occur, thanks to favorable wind and water behavior. The long-term impact of that major spill is, of course, not yet known.

On the other hand, smaller spills may exert much larger environmental impacts. A much smaller spill in the Cape Cod Canal, soon after the Argo Merchant disaster, appeared to have caused more damage as the spill occurred in a productive area, near shore and in relatively protected waters. Spills from near-shore operational platforms, particularly along the Gulf Coast, will increase the risk of damage to marine organisms; increase degradation of wetlands, beaches, and islands; and increase interference with commercial fishing operations.

All of the pricing alternatives increase domestic production at the expense of imports. Thus, risk of spills from tankers at sea or in coastal waters will be decreased proportionally. Assuming, as earlier, an average spill of about 35 barrels per million barrels shipped, the decrease (relative to the Base Case) in spill risk in 1979, expressed as barrels spilled per day, on the average ranges from about 35 barrels per day for all of the pricing alternatives to twice that (about 70 barrels per day) for immediate decontrol.

The major domestic production impact (in 1979) due to all alternatives occurs on-shore in NPC Region 6 (see Tables VI-3 through VI-18). This area comprises the Gulf Coast states. As a first-order estimate, it may be assumed that all increases in domestic production offset equivalent quantities of imports into that region. Thus import traffic will shift from the Base Case distribution to favor primarily East and, to a lesser degree, West Coast ports. The differential environmental impact is difficult to estimate, but, in very general terms, degradation of the heavier crude oil fractions and evaporation of the more toxic volatile fractions will occur at a lower rate in the colder waters along the East Coast than in the Gulf of Mexico.

To what degree this effect may be offset by changes in coastal traffic patterns carrying either domestic crude or refined products from Gulf Coast ports to East Coast ports is not known. The data necessary to estimate transportation by various modes are not available, so that even first-order estimates are not satisfactory measures of this effect.

# CHAPTER X

## ALTERNATIVES TO PRICING INCENTIVES

One of the purposes of the EPCA is to increase the supply of fossil fuels in the United States through price incentives and production requirements (see Chapter I). This is one facet of a much larger program to reduce U.S. dependence on foreign supplies of energy. EPCA also promotes strategic storage of petroleum and conservation initiatives which, along with production increases, are aimed at attaining this goal. In this EIS several pricing policies have been considered to stimulate domestic oil production (Chapter II) and analyzed for production and environmental effects. This chapter looks at alternatives to increase the supply of oil other than pricing incentives.

None of the production effects for these alternatives are quantified because of the range of potential applications and the uncertainty of the magnitude of their effect. Therefore, only qualitative effects are discussed. In any case, the range of production effects of reasonable alternatives is likely to fall between those of the Base Case and immediate decontrol. This implies no differences in 1985 and only small differences in 1979. For this reason, production estimates under decontrol were included in the analysis in Chapter VI.

As shown in Table VI-20, immediate decontrol is almost identical to case IIC, IIIA. As discussed in Chapter VII, the environmental impacts of each alternative (and by implication immediate decontrol) are not significantly different from the Base Case in 1979 and even less in succeeding years until there is no difference in 1985. The gross impacts of the alternatives discussed below are not expected to be outside the range between the Base Case and decontrol. Specific features of each alternative are discussed, however.

## A. No Action (1979 Base Case)

### 1. Introduction

The No Action policy in the context of the EPCA Stage II pricing options is the so-called "Base Case" defined earlier in Chapter II. In this case, both the composite price ($7.66) and the lower tier price ($5.15) would remain fixed, forcing the upper tier price level to be adjusted as production levels change over time. No inflationary increases would be added to the composite price under this arrangement.

Some discussion of the Base Case has already been included in Chapter VII, as a base line for comparison of the Stage II pricing alternatives. This discussion of 1979 effects is expanded in this chapter to indicate what impacts might be expected if no action is taken under Stage II.

### 2. Domestic Oil Production Levels

Total production in 1979 under the Base Case price policy is estimated to increase some 1.37 million barrels of oil per day over the 1975 production level, with most of the increase due to onshore activity in Alaska (see Table X-1). North Slope production is estimated at 1.42 million barrels per day. Production from steam (marginally) and carbon dioxide-miscible gas methods is seen to fall off, while in-situ combustion, although small in magnitude, doubles (Table X-2). Offshore production shows about a 25 percent increase (Table X-3).

On a regional basis (Table X-1), the very large increase in production from the North Slope could account, alone, for the overall increase over 1975 levels. Onshore production in NPC Region 2 (West Coast) and Region 6, and Gulf Coast offshore production all show significant increases. These increases would be offset by substantial decreases in onshore production in West Texas (Region 5) and the Northern Plain states (Regions 4 and 7), and in offshore production off the California coast (Region 2A).

### 3. Air Quality Impacts

As in Chapter VII, aggregated estimates of atmospheric emissions were made only for steam injection and in-situ combustion technologies. Of all production methods, these two technologies, as indicated in Chapter IV, are expected to exert the greatest impact on the atmospheric environment.

# TABLE X-1

## PRODUCTION LEVELS[a] - 1979 BASE CASE
(THOUSAND BARRELS PER DAY)

| NPC REGION | 1975 LEVEL | BASE CASE |
|---|---|---|
| North Slope | 0 | 1,420 |
| 1 | 190 | 120 |
| 2 | 670 | 990 |
| 2A | 220 | 90 |
| 3 | 140 | 180 |
| 4 | 620 | 470 |
| 5 | 2,050 | 1,660 |
| 6 | 2,440 | 2,630 |
| 6A | 990 | 1,350 |
| 7 | 730 | 520 |
| 8-9-10 | 220 | 160 |
| 11 | 110 | 100 |
| 11A | 0 | 60 |
| National Total | 8,380 | 9,750 |

[a] Combined totals for all production techniques.

## TABLE X-2

## PRODUCTION LEVELS BY TECHNIQUE - 1979 BASE CASE
(THOUSAND BARRELS PER DAY)

| TECHNIQUE | 1975 LEVEL | BASE CASE |
|---|---|---|
| Conventional | 8,115 | 9,540 |
| Steam Injection | 180 | 170 |
| In-situ | 5 | 10 |
| $CO_2$/Miscible | 80 | 30 |
| Micellar-Polymer | 0 | 0 |
| Caustic Flooding | 0 | 0 |
| National Total | 8,380 | 9,750 |

TABLE X-3

## OFFSHORE PRODUCTION - 1979 BASE CASE
(THOUSAND BARRELS PER DAY)

| OFFSHORE REGION | 1975 LEVEL | BASE CASE |
|---|---|---|
| 2A | 220 | 90 |
| 6A | 990 | 1,350 |
| 11A | 0 | 60 |
| OFFSHORE TOTAL | 1,210 | 1,500 |

Tables X-4 and X-5 show the quantity of pollutant emissions (see also Tables C-1, C-2, C-19, and C-20), arrayed first by NPC region and second by technology.

Note that the entries in the tables are identical, as the production estimates for 1975 and the 1979 Base Case (Tables VI-2 and VI-3) show all steam-injection production in Region 2 and all in-situ combustion in Region 6. Carbon monoxide and hydrocarbon emissions show a large increase (nearly doubling) due to in-situ production. Reference to Figures J-3 and J-5 will show that a large part of NPC Region 6 falls into non-attainment areas for CO and oxidants. Since CO problems arise primarily in urban centers at congested areas, the increases due to oil production, which would occur in remote areas, should not be subject to constraints set to meet NAAQS for CO. Hydrocarbon emissions, on the other hand, could add to the regional burden and might be constrained under regulatory policies for non-attainment areas, which policies are currently being formulated.

The national aggregate impact of emissions from the total production and consumption of petroleum production is a negligible (less than 1 percent) fraction of the production and consumption of all energy forms. On a smaller regional scale, the petroleum-derived emissions are also minor, with a single exception. Sulfur dioxide emissions from petroleum production and consumption account for about 10 percent of all sulfur oxide emissions in Region 2 (West Coast).

### 4. Water Consumption

Recent studies have indicated that despite the high current level of production associated with waterflooding, future prospects for *increased* use of the technique may be limited. That is, waterflooding is not expected to be used to any great extent under price incentives where it would not have been used without the proposed incentives. One industry observer has noted that "opportunities are dwindling rapidly to add to domestic supplies from existing fields by waterflood."[1] This near-saturation of existing fields by waterflooding has taken place because the technique was so economical even at prices of $3.00 per barrel of oil, due to

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[1] T. Geffen, "Oil Production to Expect from Known Technology," *Oil and Gas Journal* (May 7, 1973).

## TABLE X-4

## AIR POLLUTANT EMISSIONS BY REGION - 1979 BASE CASE[a]
(TONS/DAY)

| | POLLUTANT | | | | |
|---|---|---|---|---|---|
| REGION[b] | PARTICULATES | $NO_x$ | $SO_x$ | HC | CO |
| 2 | 13.6 (14.4) | 82.3 (87.1) | 185 (196) | 2.7 (2.9) | 0.5 (16) |
| 6 | 0 | 0 | 0 | 12.7 (6.3) | 62.5 (31.2) |
| NATIONAL TOTAL | 13.6 (14.4) | 82.3 (87.1) | 185 (196) | 15.4 (9.2) | 63.01 (31.8) |

[a] 1975 values shown in parentheses.

[b] Emissions are zero in all other regions.

## TABLE X-5

## AIR POLLUTANT EMISSIONS BY TECHNOLOGY - 1979 BASE CASE[a]
(TONS/DAY)

| | | | POLLUTANT | | |
|---|---|---|---|---|---|
| TECHNOLOGY | PARTICULATES | $NO_x$ | $SO_x$ | HC | CO |
| Steam Injection | 13.6 (14.4) | 82.3 (87.1) | 185 (196) | 2.7 (2.9) | 0.5 (0.6) |
| In-Situ Combustion | 0 | 0 | 0 | 12.7 | 62.5 (31.2) |
| TOTALS | 13.6 (14.4) | 82.3 (87.1) | 185 (196) | 15.4 (9.2) | 63.0 (31.8) |

[a] 1975 levels in parentheses.

low water cost. For example, in 1965 a typical Texas unit paid the West Texas Municipal Water Authority only 24 cents per thousand gallons of freshwater. Assuming a 20 to 1 water injected to oil recovery ratio (a fairly typical value in Texas and Oklahoma), this translates to a water cost of about 20 cents per barrel of oil recovery. This led to a recent study's conclusion that "the prospects that recent price rises will induce significant increased recovery via conventional waterflood appear dim."[2]

It is projected that composite national water-intensive petroleum production will grow by approximately 16.5 percent between 1975 and Base Case in 1979. On a regional basis, this translates to about a 6 percent decrease along the Gulf Coast (Regions 5, 6 and 6A) and an almost 50 percent increase in Region 2 in these enhanced-recovery operations. Water use would, thus, not appear to be a problem in the Gulf Coast area. However, it appears that freshwater supplies alone will not be able to meet a water demand increase of this magnitude in Southern California (Region 2). Alternate water sources will have to be utilized to facilitate such a growth in production. Likely candidates include saline aquifers and brine from other formations, seawater, and treated sewage effluent. Water supply should not be a serious problem in California, since the nearly 50 percent growth projected occurs despite a 10,000 barrel per day drop in steam recovery operations which present the greatest demand on freshwater.

### 5. Water Quality Impacts

Organics released in production are considered the most significant measure of aggregated impact on water quality. Estimated emissions are shown in Tables X-6 and X-7. The major potential problem areas lie in the Gulf Coast, both offshore (Region 6A) and onshore (Region 6). Much of the country shows a decline in orgranic emissions due to declining conventional production in many of the interior oil provinces. Onshore pollution shows an increase in California. The increased onshore activity could bring about an increase in the number of well failures and subsequent groundwater contamination. California is very dependent on its groundwater supplies and much of the production would take place near major unconsolidated aquifers. (See Appendix J.)

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[2] Mathematica, Inc., The Estimated Recovery Potential of Conventional Source Domestic Crude Oil, for the U.S. Environmental Protection Agency, May 1975, pp. 88-89.

## TABLE X-6

## WATER POLLUTION EMISSIONS (ORGANICS) BY REGION - 1979 BASE CASE

(TONS/DAY)

| REGION | 1975 LEVELS | 1979 BASE CASE |
|---|---|---|
| North Slope | 0 | 4.1 |
| 1 | 4.8 | 3.0 |
| 2 | 1.9 | 2.9 |
| 2A | 5.6 | 2.3 |
| 3 | 0.4 | 0.5 |
| 4 | 1.8 | 1.4 |
| 5 | 6.0 | 4.8 |
| 6 | 7.1 | 7.7 |
| 6A | 25.0 | 34.2 |
| 7 | 2.1 | 1.5 |
| 8-9-10 | 0.6 | 0.5 |
| 11 | 0.3 | 0.3 |
| 11A | 0 | 1.5 |
| National Total | 55.8 | 64.7 |

## TABLE X-7

## WATER POLLUTION EMISSIONS BY TECHNOLOGY - 1979 BASE CASE
(TONS/DAY)

| TECHNOLOGY | 1975 LEVELS | 1979 BASE CASE |
|---|---|---|
| Offshore | 35.4 | 41.0 |
| Onshore | 19.6 | 23.1 |
| Steam Injection | 0.5 | 0.5 |
| In-situ Combustion | nil[a] | nil |
| $CO_2$/Miscible | 0.2 | nil |
| Micellar-Polymer | 0 | 0 |
| Caustic Flooding | 0 | 0 |
| TOTAL | 55.8 | 64.7 |

[a] Less than 1 ton/day.

Table X-7 shows that conventional production techniques, both offshore and onshore, are by far the dominant contributors to potential water quality impacts.

The Base Case figures (Table X-1) indicate a substantial decline from 1975 in offshore Pacific production, from 220,000 barrels per day down to 90,000 barrels per day. This will decrease the probability of marine spills, such as the Santa Barbara "blowout" in 1969. This may have some beneficial socioeconomic implications, such as improving conditions for commercial fish and shellfish populations, endangered species which inhabit the coastal wetlands, and recreational beaches, fishing, and hunting territories.

### 6. Socioeconomic Factors

The major socioeconomic consequence of No Action (Base Case) would be a slight growth in employment due to the increase in production by about 16 percent relative to 1975 levels. No strong regional trends are indicated by the production estimates (Table X-1). Offshore declines in California would be offset by increases in onshore production, since displacement of workers would occur.

In absolute terms, the 21 percent increase in total production in the Pacific Region over 1975 is expected to increase employment, but since petroleum and gas presently account for only 0.15 percent of the region's employment, the impact on the region as a whole will be minor.

## B. Immediate Decontrol

There are no economic or technological barriers to immediate decontrol, but current legislation precludes this course. Future legislation could, of course, change this situation dramatically.

For old wells, immediate decontrol would remove existing incentives to defer production. As a result, output from old wells would be greater in the 1976-79 period and lower in the 5 to 10 years thereafter than it would be with continued price controls through 1979. Of course, a permanent price control program would also remove the incentive to defer production.

Investment in secondary recovery at old wells would be stimulated. Tertiary recovery would be stimulated relative to the Base Case or to any of the pricing incentives which do not allow tertiary output to sell at the market price.

There would probably be little effect on production from existing upper tier wells because the existing upper tier price is already more than enough to cover production costs. Investment in exploration and development activities would be slightly stimulated by the immediate real price increase from $11.30 to $12.00. But relative to decontrol in 1979, a policy of immediate decontrol would have little effect on long-run output from new discoveries.

Table VI-20, above, shows that immediate decontrol might stimulate production of 10.68 million barrels of oil per day in 1979. This is 10 percent greater than the Base Case, but only 0.5 percent greater than the best pricing alternative (10.63 million barrels per day in case IIC, IIIA). Furthermore, it is only 10,000 barrels per day (0.1 percent) greater than the best combination of alternatives, IIIB,C,D, IIC. Before and after 1979, immediate decontrol would exhibit even less differences until by 1985 the differences would be essentially nil. Similarly, the differences in demand for petroleum products will be small in 1979 and nil by 1985 (see Section VI.B).

## C. Institutional (Federal) Encouragement of Enhanced Oil Recovery (EOR)

It is entirely feasible for the Energy Research and Development Agency to substantially increase its R&D of enhanced oil recovery (EOR). The chief method for Federal encouragement of EOR would be Federal funding of R&D. The proper comparison is with private funding of R&D. Under either method, EOR will be used to the point where its marginal cost equals the price of the oil produced. But under private funding of R&D, marginal cost will include the cost of R&D, whereas under Federal funding it will exclude R&D costs. Thus, Federal funding will induce more EOR than private funding.

ERDA research is geared toward lowering the technological and economic barriers that limit a profit maximizing firm's exploitation of these reservoirs. Publicly sponsored research could help reduce some of the uncertainty involved in a private venture and ultimately help investment in this area compare favorably with other investment opportunities available to industry firms. At present, given the large initial capital outlays and severely discounted, uncertain, and far-distant future returns, private industry's comparison of the expected net present value of EOR investments generally compare unfavorably with alternate investments. Thus, the goal of publicly funded EOR R&D has the effect of influencing these expected net present value comparisons.

The mechanism by which EOR investments can be made relatively more attractive is ERDA's furthering of technologies that are not only more efficient but also more predictable and that decrease the amount of time investment capital is tied up before realizing returns. In so doing, ERDA research could favorably influence risk discounted expected net present value comparisons of investment opportunities. In addition, ERDA R&D program could study methods of reducing non-technical barriers to increased investment atractiveness, including environmental restrictions, market imbalances, and bottlenecks in supply material markets.

A specific ERDA R&D program has been designed and costed for the various EOR processes (steam drive, in-situ combustion, carbon dioxide miscible, surfactant/polymer and waterflooding).[1] Potential production estimates from the ERDA R&D

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[1] Lewin and Associates Inc., Research and Development in Enhanced Oil Recovery, Final Report, Part 1, for U.S. Energy Research and Development Administration, December 1976.

program were made under the assumptions of upper tier prices and current tax provisions (the Standard Economics Case). Due to large uncertainties involved with production changes attributable to the program, estimates were discounted by a factor based on an expectation of program success for each program. Figure X-1 illustrates expected daily production rates from the various processes as influenced by the proposed ERDA program through 1995, while Figure X-2 presents expected stimulated cumulative production. (Industry Base Case illustrates productivity in the absence of ERDA funded R&D, and each line in both figures is summed to the next lower line.)

While the ultimate additional recovery due to the ERDA programs is expected to be 14.3 billion barrels, the figures illustrate that the bulk of that increase comes after 1985. Nonetheless, by 1979, total daily production from the various processes is more than doubled by the stimulation. By 1985, total daily production is increased by more than 150 percent from approximately 600,000 barrels per day to 1,600,000 barrels per day. Cumulative recovery by 1985 increases by approximately 100 percent over production in the absence of stimulation. Changes in price and tax assumptions can augment the stimulative power of the ERDA R&D programs, but the vast majority of deviation from the path predicted under the standard economics assumptions comes after 1985 with virtually no deviation by 1979.

Clearly, significant increases in EOR can be realized through public funding of R&D. A cost-effective ERDA program is shown to produce dramatic results by 1985, with even more significant stimulation over longer time horizons.

From an environmental impact point of view, the success of an ERDA program would lead to greater impacts from steam injection projects than would any of the pricing options examined. Figure X-1 shows an increment of nearly 300,000 bbl/day in 1979. This should be compared to the greatest increment of 210,000 bbl/day for the options involving third stage cases IIIA and IIIB. The resulting residuals generation is given in Table X-8, compared to the pricing scenario results. All impacts would occur in California, so only Region 2 appears in the table.

Influence on $CO_2$ projects would be considerably less and would be less than the incremental effects of most of the pricing options. Only the Base Case, option IIA, and options IIC, IIIC and IIC, IIID are approximately the same. The production levels of remaining cases range from about 3 to 10 times greater than that expected through R&D efforts. R&D, as shown in Figure X-1, is not expected to produce any significant incremental production, through 1979, from in-situ, polymer, or micellar/polymer techniques.

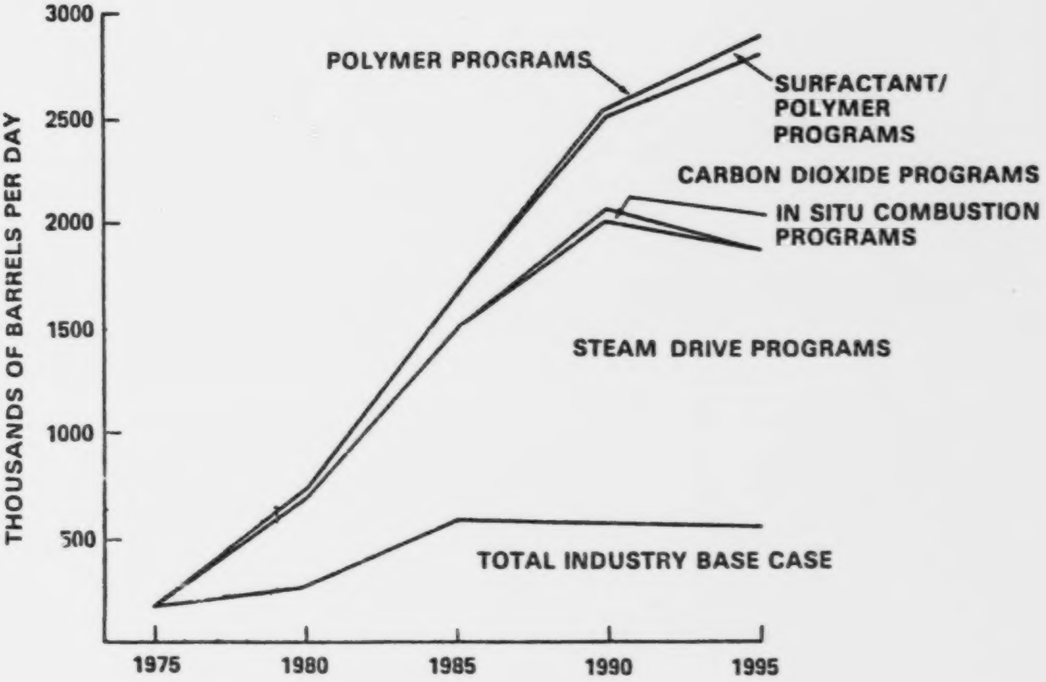

Figure X-1. Expected production rates for total of industry base case and ERDA program stimulation (standard economics). (Lewin and Associates Inc. Research and Development in Enhanced Oil Recovery, Final Report, Part 1, for U.S. Energy Research and Development Administration, December 1976, p. IV-16.)

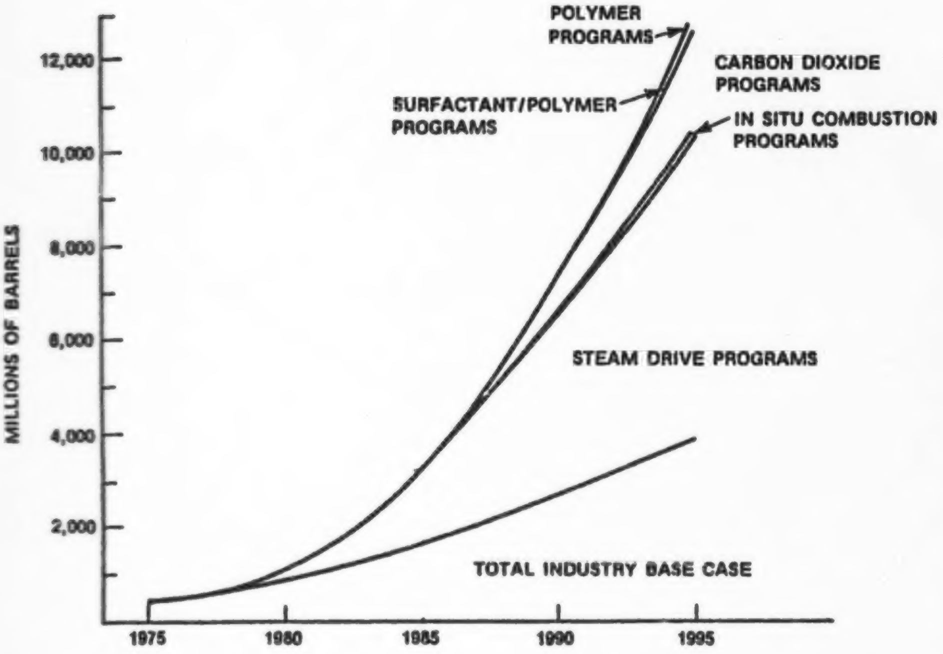

Figure X-2. Expected cumulative production from total of industry base case and ERDA program stimulation (standard economics). (Lewin and Associates Inc. Research and Development in Enhanced Oil Recovery, Final Report, Part 1, for U.S. Energy Research and Development Administration, December 1976, p. IV-17.)

TABLE X-8

## REGION 2 ATMOSPHERIC EMISSIONS - 1979: EFFECTS OF TERTIARY OIL RECOVERY R&D

(tons/day)

| POLLUTANT | 1979 BASE CASE | IIA | IIB | IIC | IIA IIIA | IIB IIIA | IIC IIIA | IIA IIIB | IIB IIIB | IIC IIIB | IIA IIIC | IIB IIIC | IIC IIIC | IIA IIID | IIB IIID | IIC IIID |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| PARTICULATES | 37.6<br>(13.6)[1] | 37.6 | 38.4<br>(14.4) | 37.6 | 40.8<br>(16.8) | 40.8 | 40.8 | 40.8 | 40.8 | 40.8 | 37.6 | 38.4 | 37.6 | 37.6 | 38.4 | 37.6 |
| $NO_x$ | 227.5<br>(82.3) | 227.5 | 232.2<br>(87.1) | 227.5 | 246.7<br>(101.6) | 246.7 | 246.7 | 246.7 | 246.7 | 246.7 | 227.5 | 232.2 | 227.5 | 227.5 | 232.2 | 227.5 |
| $SO_x$ | 512.3<br>(185.3) | 512.3 | 523.2<br>(196.2) | 512.3 | 555.9<br>(228.9) | 555.9 | 555.9 | 555.9 | 555.9 | 555.9 | 512.3 | 523.2 | 512.3 | 512.3 | 523.2 | 512.3 |
| HYDROCARBONS | 7.5<br>(2.7) | 7.5 | 7.7<br>(2.9) | 7.5 | 8.3<br>(3.4) | 8.3 | 8.3 | 8.3 | 8.3 | 8.3 | 7.5 | 7.7 | 7.5 | 7.5 | 7.7 | 7.5 |
| CO | 1.4<br>(0.6) | 1.4 | 1.3<br>(0.5) | 1.4 | 1.7<br>(0.7) | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.4 | 1.3 | 1.4 | 1.4 | 1.3 | 1.4 |
| STEAM INJECTION PRODUCTION - NO R&D[2] | 170 | 170 | 180 | 170 | 210 | 210 | 210 | 210 | 210 | 210 | 170 | 180 | 170 | 170 | 180 | 170 |
| STEAM INJECTION PRODUCTION - R&D[2] | 470 | 470 | 480 | 470 | 510 | 510 | 510 | 510 | 510 | 510 | 470 | 480 | 470 | 470 | 480 | 470 |

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[1] Emissions without R&D increased production in parentheses.

[2] (thousand bbl/day).

## D. Federal Leasing

Domestic output can be influenced by modifying both the rate of Federal leasing and environmental barriers to leasing.

The Interior Department's procedure for a lease sale is a complex sequence of events. The procedure requires:

- Calling for nominations and comments
- Selecting the tract
- Writing a draft environmental impact statement
- Holding public hearings
- Preparing a final environmental impact statement
- Reaching a final sale/no sale decision
- Conducting the actual sale

The Bureau of Land Management (BLM, the Department of Interior's leasing arm) estimates of the time involved in this procedure are illustrated in Figure X-3. BLM further notes that it often takes at least 2 years from the time of the sale to begin production, and can, in some cases, take more than 5 years to realize production. For example, offshore leases, which are issued for a 5-year period, have been frequently renewed before production actually has begun. Early this year Interior Secretary Andrus reported that there were approximately 60 non-producing leases in the Gulf area alone that held such extensions.

Based on timetable estimates similar to the one presented above, the BLM formulates planning schedules for lease sales. The proposed OCS planning schedule through 1980 (as of January 1977) is shown in Figure X-4. This plan, however, reflects a "best-case" analysis more than expected timetables. This schedule is actually a downward revision of a June 1975 version that BLM was unable to meet. Increased public resistance to sales forced BLM to postpone several Alaskan sales beyond 1980 and lengthen the budgeted time for other Alaskan sales. Several other proposed sales are expected to meet with considerable opposition and thus be delayed. After the court's decision to void the Baltimore Canyon lease sale early this year, Interior Secretary Andrus announced plans to firm up environmental review procedures. In light of the increased time more stringent review would involve, BLM is currently revising the OCS planning schedule again.

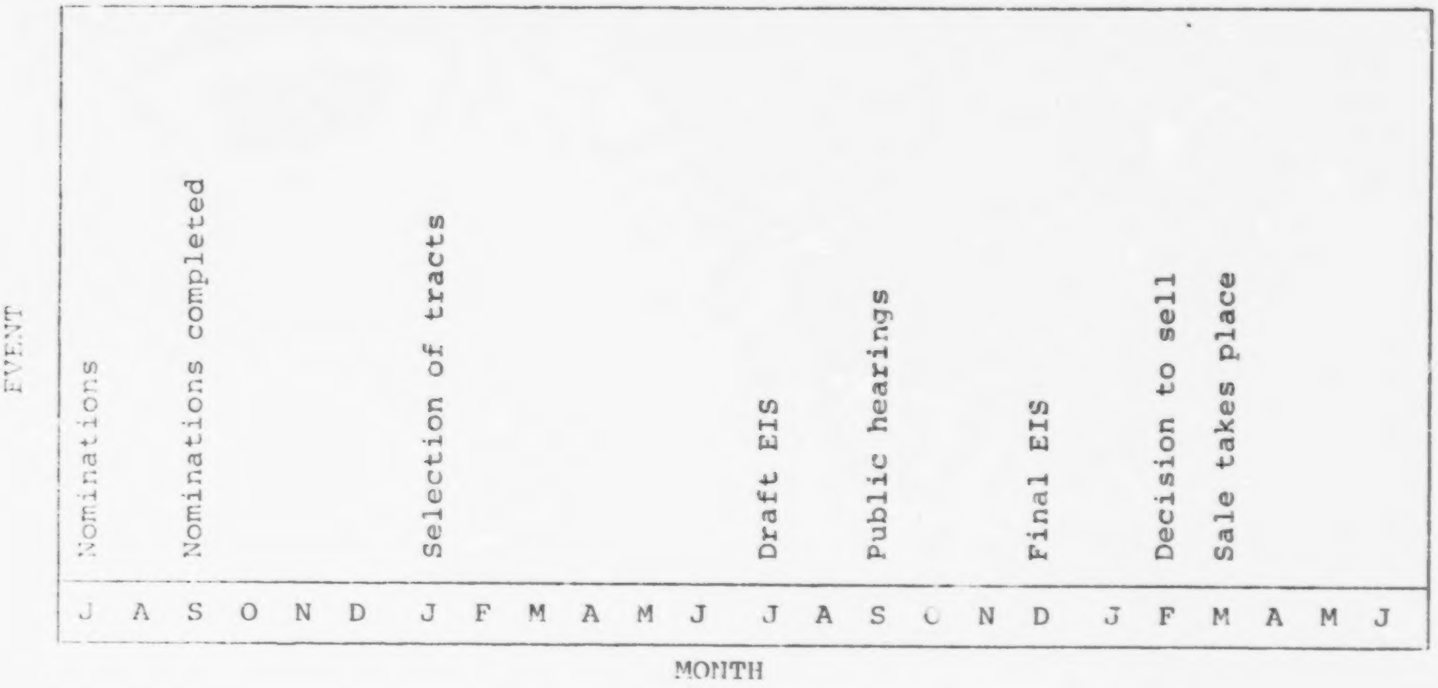

Figure X-3. BLM estimated lease sale timetable.

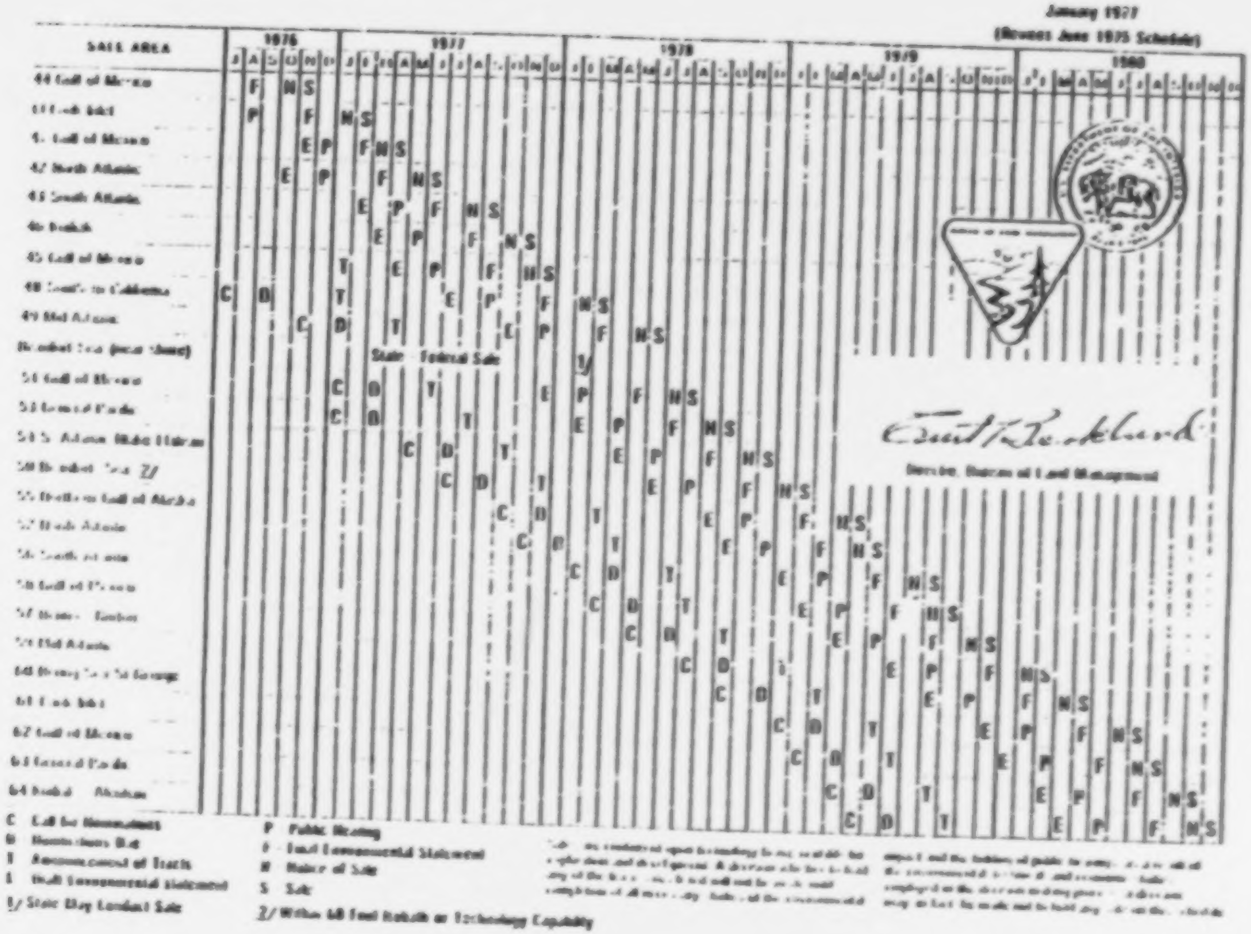
January 1977
SALE AREA
1976
1977
1978
1979
1980
State - Federal Sale
Director, Bureau of Land Management

Figure X-4. Proposed OCS planning schedule. (BLM News Release, January 12, 1977.)

It is unlikely that any significant speed-up in the process from nomination to sale can be implemented. Trends are running strongly in the opposite direction. In November 1976, the U.S. Geological Survey in an effort to promote "greater diligence in...development and production" modified its regulations for extending offshore leases. Secretary Andrus early this year empanelled a committee to review non-productive lease extensions, and further tightening of renewal standards could conceivably provide a strong incentive for more rapid exploitation of leased areas. It is unlikely, however, that major production speed-up can be realized by 1985, and virtually impossible by 1979.

In light of the improbability of significant changes in the leasing problem, no environmental impact relative to that expected under current plans would be exerted through 1979. If, for reasons unknown at this time, this program is speeded up, the effects would be increased offshore production and associated impacts.

Unlike pricing policies, accelerated OCS leasing will produce broad-scale qualitative impacts. Pricing policy options will result mainly in marginal changes in rates of production and associated impacts at existing facilities. New offshore leases, on the other hand, mean the introduction of activities and resultant impacts to new areas. No quantitative estimates of these impacts can be made at present, but the new and increased activities and effects can be described in general terms.

Increased offshore production means an increase in construction and operation of offshore facilities. Direct effects of this activity include problems of brine discharges, as discussed in Section IV.3, local ecological disruptions, restriction of other activities in the surrounding waters, increased water traffic and increased probability of oil spills. Human activities may be affected by these impacts in a number of ways.

Shipping and navigation may be negatively affected by construction and exploration activities. Platforms and increased irregular traffic may increase collision rates and reduce vessel maneuverability. Environmental impacts of such collisions include oil spills, release of debris, human injuries, and possibly release of toxic cargoes. Additional navigation hazards would be posed by floating trash from the platforms.

Commercial fisheries may be adversely affected by any damage to fish populations, by restriction of maneuverability and access to portions of fishing grounds resulting from construction. Also, potential disruption of the ocean bottom may hinder dredging and trawling. Exposure to oil spills may affect fish larvae and eggs, and shellfish, all of which are unable to avoid contaminated water. Nearshore populations would be more affected than those far offshore. Discharge of formation waters, which contain low levels of hydrocarbons, could have a variety of sublethal toxic effects. Discharge of drill cuttings and muds are expected to have a minimal impact, except in the immediate area of discharge.[1]

Sport fishing will probably be benefited by the artificial reef effect of platforms. Local disruptions may occur in the event of an oil spill, but no long-term adverse effects are likely.[2]

If pipelines are laid through areas fouled by ocean dumping, toxic materials and non-toxic sediments may be resuspended until the pipe-laying is completed.

Offshore and onshore archaeological and historical sites may be damaged or destroyed during construction, drilling, and pipe-laying. Oil spills can damage such sites and interfere with radiocarbon dating.

Mining of ocean sand and gravel, which is likely to develop more in the coming years, will be impaired by construction of platforms and pipelines, and by spills, which will remove certain areas from consideration.

Onshore effects of offshore oil development include direct environmental impacts, and direct and indirect socioeconomic impacts. A variety of activities would be stimulated in the onshore regions adjacent to the offshore facilities, resulting in economic and population expansion. The greatest changes would be in construction and private investment.[3] Both positive and negative impacts would result.

Supporting industries which might be expanded or established to accommodate offshore oil production include refineries, gas processing plants, pipeline installation, and other transportation systems. A population influx will probably occur resulting in expansion of services such as utilities, sanitation, retail stores, public administration, and mass transport. Reallocation of capital to the expanding area would occur. All phases of construction would probably be stimulated, to meet the needs of an increasing population.

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[1] U.S. Department of Interior, Draft Environmental Statement, Proposed 1977 OCS Oil and Gas Lease Sale Offshore the North Atlantic States, OCS Sale No. 42, 1976, p. 862.

[2] U.S. Department of Interior, Proposed 1977 OCS Oil and Gas Lease Sale Offshore the North Atlantic States, OCS Sale No. 42, p. 885.

[3] U.S. Department of Interior, Proposed 1977 OCS Oil and Gas Lease Sale Offshore the North Atlantic States, OCS Sale No. 42, p. 897.

Land use would be affected both by the need for space for support facilities and by the additional needs of the population. In many cases, conflicts will arise between the two. Rezoning may be necessary to accommodate oil production and related activities, as considerable space is required for an onshore operations base, gas processing plants, pipeline terminals and storage areas, onshore pipelines and corridors, pipecoating yards, platform construction yards, support service companies, and refineries. Whether new refineries are built or existing facilities expanded would depend in part on the location of the demand for refined products.

Facilities for tankers would generally be located in ports already able to accomodate these vessels, but the additional activity may still prove a strain. Since smaller tankers are used for domestic transport than for foreign shipments, the total volume of local tanker traffic will increase. Commercial fishing vessels may find themselves in competition with oil production servicing vessels for port berthing facilities, even in ports which do not receive tankers. Adverse effects on commercial fisheries would in turn adversely affect the economy of the port area.

Recreational activities may also suffer from competition for land with OCS onshore facilities and with residential demands. Additional impairment of recreational areas may result from spills and pipeline seeps. These events would damage and possibly eliminate swimming areas, boating areas, and fishing. Aesthetic degradation could further affect camping and hiking areas. Such degradation includes the visibile effects of storage facilities, pipelines and refineries, soiling by spills and air pollution, and noise from construction and operation.

Effects on the natural environment would arise primarily from disruptions caused by construction, and damage from oil spills. Water quality may be adversely affected by runoff from onshore construction, which would increase turbidity and siltation. Gas processing and oil refining would both impose additional burdens on local water supplies, and could also reduce air quality.  Air quality could further be impaired by the increased use of motor vehicles, electricity, heating fuel, and services, associated with population expansion.

# CHAPTER XI

## IRREVERSIBLE AND IRRETRIEVABLE COMMITMENT OF RESOURCES

The goal of the pricing actions -- to stimulate the exploration and production of crude oil -- represents a one-way, irreversible process. Once a site gives up its reserve, it can never be so used again. And once the energy content of the oil is consumed, it is lost to subsequent reuse.

According to a 1975 report, the National Ocean Policy Study (NOPS), from the Senate Committee on Commerce, "the appropriate rate for the development of domestic resources is dependent upon which estimates [of total United States oil] are correct."[1] If the optimistic, or high, estimates are valid, says the report, then domestic reserves can be developed full speed ahead, confident that more long-term and perhaps renewable sources of energy can be developed in time. But if the pessimistic, low estimates are correct, then government needs to place curbs on energy demand, to speed development of alternative energy sources, and to limit domestic oil production "below the maximum efficient rate."

However, as shown in Table XI-1, the greatest possible difference in levels of production in 1979 is between the Base Case and immediate decontrol. If that difference (930,000 barrels per day) is maintained from 1976 until 1985 (which overestimates the effects of the policies because 1979 represents the point in time of largest divergence) then the cumulative difference is less than 3.4 billion barrels (930,000 x 365 x 10) or 9 months of supply at the 1985 rate of 12.21 million barrels per day. This is well within the uncertainty of reserve levels in terms of years of production remaining.

In addition, the problem of early depletion of domestic oil reserves is at least partially offset by the same pricing policies. Though total absolute oil-in-place is fixed, proved reserves and recoverable reserves vary with price (and other factors). The pricing policies stimulate both enhanced recovery techniques and new exploration which will, in turn,

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[1] Deborah Shapley, "Senate Study Predicts U.S. Oil 'Exhaustion'," Science (March 21, 1975).

## TABLE XI-1

## DOMESTIC OIL PRODUCTION UNDER VARIOUS PRICING ALTERNATIVES, 1979 AND 1985

(Millions of Barrels Per Day)

| CRUDE PRICE OPTION | 1975 | 1979[1] | 1985[1] |
|---|---|---|---|
| Base Case | 8.38 | 9.75 | 12.21 |
| Stage IIA | -- | 10.46 | 12.21 |
| IIB | -- | 10.47 | 12.21 |
| IIC | -- | 10.38 | 12.21 |
| Stage IIA, IIIA | -- | 10.53 | 12.21 |
| IIB, IIIA | -- | 10.47 | 12.21 |
| IIC, IIIA | -- | 10.63 | 12.21 |
| IIA, IIIB | -- | 10.47 | 12.21 |
| IIB, IIIB | -- | 10.40 | 12.21 |
| IIC, IIIB | -- | 10.58 | 12.21 |
| IIA, IIIC | -- | 10.49 | 12.21 |
| IIB, IIIC | -- | 10.50 | 12.21 |
| IIC, IIIC | -- | 10.40 | 12.21 |
| IIA, IIID | -- | 10.48 | 12.21 |
| IIB, IIID | -- | 10.49 | 12.21 |
| IIC, IIID | -- | 10.40 | 12.21 |
| IIIA,C,D, IIC | -- | 10.67 | 12.21 |
| Decontrol (in 1976) | -- | 10.68 | 12.21 |

[1] Include 1.42 Alaskan North Slope and 0.20 NPR-1.

increase levels of recoverable and proved reserves. The issue of earlier depletion of oil under the alternatives should not be a factor.

To the extent that freshwater is used to aid oil recovery it is lost to other purposes. For the most part its use can and will be avoided, but some at least will probably be required for steam injection, largely in California. Still (as shown in Section VII.A.3), worst case estimates indicate that slightly more than one million barrels of water per day may be used. This slightly less than 50,000 acre-feet per year is small compared to the some 15 million acre-feet pumped annually from ground waters of California.

# CHAPTER XII

## RELATIONSHIP BETWEEN SHORT-TERM USES OF MAN'S ENVIRONMENT AND THE MAINTENANCE OF LONG-TERM PRODUCTIVITY

The impact of oil production activities on the environment are for the most part short term as defined by the typical lifetime of an oil production project (ranging from 20 to 30 years). When weighed against the substantial benefits of oil as an energy source, they appear to be of minor importance, especially when all the precautions available to producers are taken. However, it should be realized that the use of oil is also short term, although it may bridge the gap to advanced energy-producing technologies.

The water demands of secondary and tertiary recovery in arid regions, in particular for steam flooding projects in California, may pose a short-term demand on local water supplies. In general, however, sufficient produced water and salt water makeup is available. Still, the wastewaters produced by the operation might contaminate surface and ground waters. When the project ends, local water resources are applied to other uses and pollutants no longer enter the streams, although polluted waters may require many years to purge themselves of their loads. Since water is a renewable resource, its availability in the long term should not be jeopardized.

The air-polluting effects of oil recovery are not severe and are limited to the duration of the project. Therefore, the long-term productivity of air as a resource will be maintained.

Disruption of the land, and changes in local land use, may last only as long as a given well is productive. Without tertiary recovery, the average duration of the process is 20 to 30 years. In some areas another 20 years might be required, if restoration began immediately after depletion, for the total revegetation of the area. The implementation of tertiary recovery, in most cases, would remove little additional land for other uses, but would extend the life of the well and thus would delay restoration of the land. Its long-term productivity, however, is maintained with reclamation.

The most well-known environmental impact of offshore oil recovery is the effect of oil spills. These are limited to the duration of the project. Because of increasing awareness and concern, tighter controls on offshore rigs and transportation systems have been imposed to limit the number of spills and volume of oil spilled. The situation has improved considerably over the years, but oil spills continue to threaten especially local environments, and their effect should not be overlooked. But, except for the possibility of dramatic reductions in biota that may be caused by chronic or accidental releases of oil, the resources should regenerate over the long term and their productivity be maintained.

# CHAPTER XIII

## CONSIDERATIONS OFFSETTING THE ADVERSE ENVIRONMENTAL IMPACTS OF THE PROPOSED ACTION

The emphasis of the price incentives on tertiary recovery should permit more efficient utilization of resources. Some of the oil usually left in the ground after primary and secondary recovery (sometimes two-thirds of the reservoir's oil) may now be tapped. This not only carries its own direct economic advantages, but effectively extends the positive "secondary" economic effects as well. Local economies that are dominated or significantly influenced by crude oil production are obvious beneficiaries.

Furthermore, price increases in oil will stimulate energy conservation. As a result of recent price increases, oil consumption in this country is dropping. The use of petroleum overall fell 1.9 percent in 1975, and the American Petroleum Institute reported an 8.9 percent decrease in the demand for refineries' products.

Despite the fact that total petroleum use fell, net crude oil imports increased 15.1 percent in 1975 and oil continued to be America's largest energy source (supplying 46 percent of total energy). The United States is not only still vulnerable to an oil embargo, but is perhaps more vulnerable than in 1973. Thirty-seven percent of imports comes from Arab members of OPEC (all OPEC countries together supply us with 82 percent of our imports). Thus, the shift toward more domestic production of crude oil should reduce the degree of control that other countries may exercise.

# APPENDIX A

## IMPACTS OF TRACE METALS AND HYDROCARBONS DISCHARGED INTO COASTAL WATERS

# APPENDIX A

## IMPACTS OF TRACE METALS AND HYDROCARBONS DISCHARGED INTO COASTAL WATERS

The principal cause for concern regarding the discharge of oilfield brines into coastal waters is the metals and oil hydrocarbons present in trace quantities. Trace metals present in oilfield brines include arsenic, cadmium, chromium, copper, lead, mercury, nickel, silver, and zinc. Table A-1 (presented above as Table IV-3) presents the concentrations of these metals as measured in oilfield brines in various geographical regions. Also included in Table A-1 are the seawater concentrations of these metals, their common chemical forms, and the EPA maximum acceptable concentrations.

In contrast to the trace metals for which some, although distinctly limited, data are available regarding their concentrations in produced water, almost no information is available on the quantities of specific oil hydrocarbon components in oilfield brines. Perhaps the main reason for this is that both Federal and state regulations regarding brine discharge are expressed in terms of the maximum total oil allowable in discharged produced water and not in terms of specific oil hydrocarbon components.

The relative proportions of various hydrocarbons in produced water are probably not representative of the proportions found in the parent crude oil. Those hydrocarbons which are most soluble in water -- for example, the aromatic hydrocarbon components -- would be preferentially concentrated in the brines, since the brines essentially consist of a water extract of crude oil. Despite the absence of actual measurements of specific oil hydrocarbon components in produced water, it is possible to estimate these quantities on the basis of composition data on artificial "water-soluble fractions" of crude oil. Anderson et al.[1] prepared water-soluble fractions of two crude oils, and analyzed the

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[1] J.W. Anderson et al., "Characteristics of Dispersions and Water-Soluble Extracts of Crude and Refined Oils and Their Toxicity to Estuarine Crustaceans and Fish," Marine Biology 27 (1974).

# TABLE A-1

## PRODUCED WATER CONSTITUENTS

| PARAMETER | SEAWATER[a] |  | BRINES |  |  |  |  |  |  | WATER QUALITY CRITERIA LIMITS[f] |  |
|---|---|---|---|---|---|---|---|---|---|---|---|
|  | FORM | PPM | FORM[b] | LOUISIANA[c] (ppm) | ALASKA[d] (ppm) | CALIFORNIA[c] (ppm) | TEXAS[c] (ppm) | LA. CONCENT.[e] RATIO | AK. CONCENT.[e] RATIO | MAXIMUM ACCEPTABLE CONCENTRATIONS (ppm) | MINIMUM RISK THRESHOLD (ppm) |
| Ag | $AgCl_2^{--}$ | .0003 |  |  | <.010 | .03 | <.01-.10 |  | <3.3 | .005 | .001 |
| As | $AsO_4H^{--}$ | .003 | $HAsO_2^-,H_2AsO_4^{--}$ |  | <1-1.404 | .001-.08 | <.01-<.02 |  | <333-468 | .05 | .01 |
| Cd | Cd++ | .00011 | $CdSO_4,CdCl_2$ | <.005-.675 | .001 | .02-.18 | <.02-.193 | <45-6136 | 736 | .01[h] | .0002 |
| CN |  |  |  | <.01-.10 |  | 0-.004 |  |  |  | .01 | .005 |
| Cr | $CrO_4,Cr^{3+}$ | .00005 |  |  | <.01-.10 | .02-.04 | <.01-.23 |  | <200-<200 | .1 | .05[i] |
| Cu | Cu++ | .003 | Org. Acid Salt |  | .086 | .05-.116 | <.01-.38 |  | 28.7 | .05[h] | .01 |
| Hg | $HgCl_2,HgCl_4^{--}$ | .00003 |  | <.0995 | <.002-<.010 | .0005-.002 | <.0001-.13 | <16.7 | <4-<20 | .0001 |  |
| Ni | Ni++ | .0054 |  |  | .005-.430 | .1-.29 | <.01-.44 |  | .9-79.6 | .1 | .002 |
| Pb | Pb++,PbCl+ | .00003 | $Pb(HCO_3)_2$ |  | <.01-.39 | 0-.28 | <.01-.22 |  | <33.3-1300 | .05 | .01 |
| Zn | Zn++ | .01 | $ZnCl_2,ZnSO_4$ |  | .277 | .05-3.2 | .1-.27 |  | 27.7 | .1[h] | .02 |
| Ca | Ca++ | 400 |  | 2,473[g] | 3,725 |  |  | 6.2 | 9.3 |  |  |
| Mg | Mg++ | 1,350 | Mg++ | 747[g] | 145.8 |  |  | .55 | .11 |  |  |
| Na | Na++ | 10,500 | Na+ | 44,607[g] | 7.650 |  |  | 4.2 | .73 |  |  |
| Cl | $Cl^-$ | 19,000 | $Cl^-$ | 61,000[g] | 13,953 | 17,230-21,000 | 42,000-62,000 | 3.2 | .73 |  |  |
| Oil & Grease |  |  |  | 202[g] | 36 | 56-359 |  |  |  |  |  |
| Phenols |  |  |  |  | 3.100 | .35-2.1 | 5.3 |  |  |  |  |
| BOD |  |  |  |  | 683 | 370-1,920 | 126-342 |  |  |  |  |
| COD |  |  |  |  | 1,671 | 400-3,000 | 102-562 |  |  |  |  |
| Total Solids |  | 34,325 |  | 110,200 | 23,842 |  |  | 3.2 | .69 |  |  |
| TDS |  |  |  | 113,000 | 23,482 | 21,700-40,400 | 906-169,000 |  |  |  |  |
| TSS |  |  |  | 22-390 | 99 | 1-60 | 12-656 |  |  |  |  |
| TOC |  |  |  | 413 |  |  |  |  |  |  |  |

NOTE: Footnotes are on the following page.

## FOOTNOTES TO TABLE A-1

[a] M.G. Gross, Oceanography: A View of the Earth (Englewood Cliffs, N.J.: Prentice-Hall, 1972).

[b] Gene A. Collins, Geochemistry of Oilfield Waters (New York: Elsevier Scientific Publishing Co., 1975).

[c] U.S. Environmental Protection Agency, Development Document for Interim Final Effluent Limitations Guidelines and New Source Performance Standards for the Offshore Segment of the Oil and Gas Extraction Point Source Category, 1975.

[d] Values are averages of values from four permit application forms submitted to U.S. Army Corps of Engineers. See text.

[e] Concentration Ratio = (ppm Brine)/(ppm Seawater).

[f] Water Quality Criteria limits, October 1973, from Environmental Studies Board, U.S. Environmental Protection Agency - Water Quality Criteria 1973, 1973.

[g] Gene A. Collins, "Geochemistry of Some Petroleum Associated Waters from Louisiana," U.S. Bur. Min. Rep. Invest., No. 7326, 1970.

[h] Synergistic effects have been observed when cadmium, copper, and zinc are present simultaneously. Under those conditions Maximum Acceptable Concentrations should be reduced by an order of magnitude.

[i] When oysters are present the Maximum Acceptable Concentration should be reduced to 0.01 ppm.

Source: Energy Resources Co. Inc., Benefits Study of Effluent Limitations for the Offshore Segment of the Oil and Gas Extraction Point Source Category, p. 3-6.

water from these two preparations for specific hydrocarbon content. The water-soluble fraction (WSF) was prepared by mixing oil and seawater gently for 20 hours at 20° C, and then allowing the mixture to separate for 1 to 6 hours. The water was then analyzed for hydrocarbon content. The results of the analysis are shown in Table A-2. To determine the degree to which the water-soluble fraction of oil is enriched in aromatic hydrocarbons as compared to the parent oil, Anderson compared concentrations of the $C_{12}$-$C_{24}$ n-paraffins, and the $C_{10}$-$C_{17}$ aromatics in the whole oils and the WSFs prepared from them. The results, shown in Table A-3, show that the ratio of aromatics to paraffins is 14.29 times as great in the WSF as it is in South Louisiana crude oil, and 125.00 times as great in the WSF prepared from Kuwait oil as it is in the parent oil. Hence, the greater solubility of aromatics compared to paraffins is a key factor in determining the composition of the hydrocarbon content of the oilfield waters.

A comparison of the concentrations of trace metals and oil hydrocarbons that have been reported in produced water (see Table A-1), with concentration levels of these same substances that have been demonstrated to have toxic (lethal and sublethal) effects on marine and estuarine organisms, shows that produced water concentrations of trace metals and oil hydrocarbons are capable of inducing a wide range of toxic effects on organisms exposed to them. The literature on the toxic effects of oil hydrocarbons and trace metals is extensive and rapidly expanding. A few examples will serve to indicate the kinds of impacts that have been associated with concentrations of trace metals and oil hydrocarbons actually found in produced water; a much more detailed presentation can be found in Energy Resources' study of effluent limitations for the oil and gas extraction industry.[2]

1. An exposure of killifish (Fundulus heteroclitus) to concentrations of silver of 0.04 mg/l resulted in 50 percent mortality within 96 hours;[3] developmental

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[2] Energy Resources Co. Inc., Benefits Study of Effluent Limitations for the Offshore Segment of the Oil and Gas Extraction Point Source Category, Report submitted to U.S. Environmental Protection Agency, 1977.

[3] E. Jackim et al., "Effect of Metal Poisoning on Five Liver Enzymes in the Killifish (Fundulus heteroclitus)," Journal of the Fisheries Research Board of Canada 27 (1970): 383-390.

## TABLE A-2

## HYDROCARBON CONCENTRATIONS OF CRUDE OIL WATER-SOLUBLE FRACTIONS

| COMPOUND | SOUTH LOUISIANA CRUDE OIL | KUWAIT CRUDE OIL |
|---|---|---|
| ALKANES | | |
| Ethane | 0.54 | 0.23 |
| Propane | 3.01 | 3.30 |
| Butane | 2.36 | 3.66 |
| Isobutane | 1.69 | 0.90 |
| Pentane | 0.49 | 1.31 |
| Isopentane | 0.70 | 0.98 |
| Cyclopentane + 2-Methylpentane | 0.38 | 0.59 |
| Methylcyclopentane | 0.23 | 0.19 |
| Hexane | 0.09 | 0.29 |
| Methylcyclohexane | 0.22 | 0.08 |
| Heptane | 0.06 | 0.09 |
| $C_{16}$ n-Paraffin | 0.012 | 0.0006 |
| $C_{17}$ n-Paraffin | 0.009 | 0.0008 |
| TOTAL $C_{12}$-$C_{24}$ n-paraffins | 0.089 | 0.004 |
| AROMATICS | | |
| Benzene | 6.75 | 3.36 |
| Toluene | 4.13 | 3.62 |
| Ethylbenzene + m-, p-Xylenes | 1.56 | 1.58 |
| o-Xylene | 0.40 | 0.67 |
| Trimethylbenzenes | 0.76 | 0.73 |

Source: Anderson et al., "Characteristics of Dispersions and Water-Soluble Extracts," 1974.

## TABLE A-2 (CONT.)

| COMPOUND | SOUTH LOUISIANA CRUDE OIL | KUWAIT CRUDE OIL |
|---|---|---|
| AROMATICS (CONT.) | | |
| Naphthalene | 0.12 | 0.02 |
| 1-Methylnaphthalene | 0.06 | 0.02 |
| 2-Methylnaphthalene | 0.05 | 0.008 |
| Dimethylnaphthalenes | 0.06 | 0.02 |
| Trimethylnaphthalenes | 0.008 | 0.003 |
| Biphenyl | 0.001 | 0.001 |
| Methylbiphenyls | 0.001 | 0.001 |
| Dimethylbiphenyls | 0.001 | 0.001 |
| Fluorene | 0.001 | 0.001 |
| Methylfluorenes | 0.001 | 0.001 |
| Dimethylfluorenes | 0.001 | 0.001 |
| Dibenzothiophene | 0.001 | 0.001 |
| Phenanthrene | 0.001 | 0.001 |
| Methylphenanthrenes | 0.002 | 0.001 |
| Dimethylphenanthrenes | 0.001 | 0.001 |
| TOTAL SATURATES | 9.86 | 11.62 |
| TOTAL AROMATICS | 13.90 | 10.03 |
| TOTAL DISSOLVED HYDROCARBONS MEASURED | 23.76 | 21.65 |

## TABLE A-3

## AROMATIC AND n-PARAFFIN CONTENT OF SOUTH LOUISIANA AND KUWAIT CRUDE OILS AND THEIR WATER-SOLUBLE FRACTIONS (WSF) AND CALCULATED AROMATIC-ENRICHMENT FACTORS (AEF)

| | AROMATICS | | n-PARAFFINS | | AROMATICS/ n-PARAFFINS | | |
|---|---|---|---|---|---|---|---|
| OIL | Oil (%) | WSF (ppm) | Oil (%) | WSF (ppm) | Oil | WSF | ASF |
| South Louisiana | 0.94 | 0.305 | 3.98 | 0.089 | 0.24 | 3.43 | 14.29 |
| Kuwait | 0.60 | 0.075 | 4.00 | 0.004 | 0.15 | 18.75 | 125.00 |

NOTE: $$\text{AEF} = \frac{(\text{Aromatics/n-paraffins})_{\text{WSF}}}{(\text{Aromatics/n-paraffins})_{\text{Oil}}}$$

Source: Anderson et al., "Characteristics of Dispersions and Water-Soluble Extracts," 1974.

abnormalities in the sea urchin Arbacia have been induced by exposure to silver concentrations of 0.0005 mg/l.[4] (Measurements of silver in produced water have yielded concentrations as high as 0.1 mg/l in Texas and a mean level of 0.03 mg/l in California.[5])

2. Copper, which typically occurs in produced water at a concentration level of 0.1 mg/l, has been shown to inhibit the growth of algae and polychaetes at concentrations of 0.00068 mg/l and 0.00025 mg/l respectively.[6]

3. Exposure of the crustacean Mysidopsis almyra to 8.7 mg/l dissolved oil hydrocarbons induced 50 percent mortality within 48 hours[7] and sublethal effects have been associated with soluble aromatics at concentrations down to 0.01 ppm.[8] As shown in Table A-2, the total dissolved hydrocarbon concentration in an extract prepared from Louisiana crude oil is 23.8 mg/l and the total dissolved aromatic fraction is 13.9 mg/l. Since current EPA BPCTCA regulations call for a maximum level of 48 mg/l total oil hydrocarbons in discharged produced water, it is safe to assume that the produced water, even after treatment,

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[4] National Academy of Sciences and National Academy of Engineering, Water Quality Criteria, Washington, D.C., 1972, p. 255.

[5] U.S. Environmental Protection Agency, Development Document for Interim Final Effluent Limitations Guidelines and New Sources Performance Standards for the Offshore Segment of the Oil and Gas Extraction Point Source Category, September 1975.

[6] M. Bernhard and A. Zattera, "Major Pollutants in the Marine Environment," in E.A. Pearson and E. Frangipane, eds., Marine Pollution and Marine Waste Disposal (Oxford: Pergamon Press, 1975).

[7] Anderson, 'Characteristics of Dispersions and Water-Soluble Extracts of Crude and Refined Oils," pp. 75-78.

[8] W. Harrison et al., "Crude Oil Spills - Disappearance of Aromatic and Aliphatic Components from Small Sea-Surface Slicks," Environmental Science & Technology 9 (1975): 231-234.

is generally saturated with dissolved oil hydrocarbons and hence the levels of approximately 20 ppm dissolved oil hydrocarbons and 14 ppm dissolved aromatics are to be expected.

The literature on the toxic effects of trace metals and oil hydrocarbons thus supports the assertion that the constituents of oilfield brine, taken at concentrations at which they commonly occur in oilfield brine, are potentially capable of inducing both lethal and sublethal effects on certain organisms exposed to them. Admittedly, however, great caution should be used in extrapolating from laboratory toxicity data to the prediction of impact in the field, and it is not the intent here to claim that specific impacts will in fact result from brine discharge. Although experimental data are undoubtedly useful in giving some idea of the risks that may be posed by various concentration levels of particular oilfield brine constituents, it is also important to keep clearly in mind the limitations of the data. A few of these limitations are:

1. The reaction of an organism to toxic pollutants will be modified by a number of environmental factors, so that the wide diversity of possible environments, combined with the even greater difference between any natural marine environment and a laboratory bioassay system, make it extremely difficult to safely extrapolate toxicity data obtained in one experimental system under a highly specific set of conditions to any other system or any other set of conditions.

2. Synergistic or antagonistic effects are not taken into account.

3. Laboratory animals used in bioassay experiments are often chosen on the basis of being easy to raise or maintain, rather than on the basis of ecological importance in an area actually being impacted.

4. Toxicity results may vary widely depending on the age of an organism or the season when it was collected. In chronically polluted waters, selection pressures may result in strains of organisms which are unusually adapted to relatively high pollutant concentrations, and which may thus give misleading impressions if used in toxicity experiments.

5. Toxicity of a pollutant may vary greatly depending on the mode of presentation. Benthic organisms exposed to trace metals in sediments are affected quite differently than fish exposed to the same pollutant in the water column.

Most of the reported effects are lethal in nature. This, however, should not be taken as meaning that lethal effects are the main cause of concern. In fact, sublethal effects may be of much greater concern, in part because they can occur over a range of concentrations much wider than those required to actually kill organisms, and in part because they are more insidious. Direct kills are easy to observe. Sublethal effects which may impair the ability of a population of a species to maintain itself (e.g., by reducing reproductive capacity) while not directly killing individual organisms, may manifest themselves only after considerable periods of time. The principal reason for the preponderance of lethal effect studies in the toxicological literature is simply that it is far easier to perform acute toxicity experiments than it is to perform long-term chronic bioassay experiments.

Among the important sublethal effects of brine pollutants are the following:

1. "Economic effect," i.e., effects which reduce the marketability of economically important marine organisms. An example is the "greening" of oysters in solutions containing moderate concentrations of copper, due to the bioaccumulation of copper by the organism.

2. Histo- and cytopathology -- Exposure to sublethal concentrations of trace metals and hydrocarbons has been shown to produce extensive tissue damage, at the light or electron microscope levels, in gill, kidney, and liver tissue. Such damage can reduce life expectancy and productivity and, if it occurs in lateral line or taste bud tissues, can reduce the extent to which a fish can find food or avoid predation.

3. Biochemical alterations -- Some studies have been concerned with the effect of trace metals on the assay levels of certain key enzymes in fish, and other studies have tried to determine by electrophoresis the effect of sublethal exposures on the concentrations of various serum proteins. The use

of acetylcholinesterase levels as an indicator of exposure to certain organophosphorus pesticides has received particular attention. Although such biochemical parameters are hard to interpret in terms of effects on ecosystems, they seem to indicate pathological conditions which have the potential of reducing the survival rates, fertility, or adaptability of a species.

4. Physiological parameters -- Included in this category are effects on blood ion concentration, EKG rates, blood cholesterol levels or hematocrit levels of affected fish populations. A small number of studies have been conducted on the effects of pollutants on these parameters, particularly on freshwater fish; an excellent review is provided by Sprague.[9] Again, data such as these are hard to interpret directly, but they can be used as "early warning signs" of potentially dangerous toxic conditions.

5. Effects on growth and productivity.

6. Effects on viability, as indicated by rates of $O_2$ consumption, particularly in gill tissue.

7. A toxic substance, even if it creates no noticeable toxic effects by itself, can significantly reduce the resistance of an organism to other environmental stressors, including DO stress, salinity stress, and thermal stress.

8. Behavioral effects -- Included in this category are effects on mating or swimming behavior which might affect survival and growth rates of the organism and species. Another important sublethal behavioral response to pollutants is the avoidance response; that is, the avoidance by fish of waters which contain particular levels of a trace metal. Such an effect is important because it can prevent spawning migrations of fish. Sprague et al.[10]

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[9] J.B. Sprague, "Measurement of Pollutant Toxicity to Fish -- III, Sublethal Effects and 'Safe' Concentrations," Water Research 5 (1971): 257.

[10] J.B. Sprague et al., International Journal of Air and Water Pollution 9 (1965): 531-545.

note that "in the laboratory, avoidance responses can be obtained at less than one-tenth of the incipient lethal level (i.e., threshold) concentrations." Such behavioral effects are most important if they affect behavioral patterns important for survival. Stephenson and Taylor, for example, have noted a decrease in burrowing activity of clams associated with sublethal copper toxicosis[11] and in an elegant experimental system involving the use of a radioactive mercury tracer, Kania and O'Hara demonstrated that sublethal exposures to mercury(II) reduced the efficiency of the mosquitofish *Gambusia* in escaping predation by the bass *Micropterus*.[12]

9. Reproductive effects -- Experimental data include some effects of trace metals on development. Such effects can range from lethality of eggs and embryos to minor development defect initiation (teratogenesis) which could reduce the survival rate of the hatched young. Generally, such effects occur at levels far below the lethal concentrations for the organisms.

10. Aggregate effects on production in communities -- A few experiments have been done on the effects of pollutants on harvestable crops, productivity, and diversity in natural freshwater ecosystems; presumably, in the near future similar studies will be initiated in marine or estuarine systems.

11. Effects on performance (e.g., swimming ability).

12. Effects on disease resistance.

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[11] R.R. Stevenson and D. Taylor, "Influence of ETDA on Mortality and Burrowing Activity of Clams (*Venerupis decussata*) Exposed to Sublethal Concentrations of Copper," *Bulletin of Environmental Contamination and Toxicology* 14(3) (1975): 304-308.

[12] Kania and O'Hara, "Behavioral Alterations in a Simple Predator-Prey System Due to Sublethal Exposure to Mercury," *Transactions of the American Fisheries Society* 1 (1974): 134-136.

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Each of the effects discussed above is important in that it can produce gross alterations in the populations, productivity, and diversity of a community without producing any significant mortality effect in a laboratory bioassay system.

The impact exerted by contaminants present in discharged produced water depends on the concentration levels of the contaminants to which biota in the receiving waters are exposed. The concentrations will in general be a maximum in the immediate vicinity of the discharge point, and will decrease with increasing distance from the point of discharge. An analysis of the available data on the effects of brine toxicants on marine and estuarine organisms, taken in conjunction with data on produced water contaminant concentrations, suggests that a dilution of approximately 1,500 parts receiving water to 1 part oilfield brine can be considered "safe"; i.e., oilfield brine diluted to this extent should produce no significant level of lethal or sublethal effects on resident organisms and will not result in the bioaccumulation of brine constituents to dangerous levels in organisms used for human food. Needless to say, uncertainties in the knowledge of brine toxicant concentrations, the considerable variability that has been reported in brine composition, and all the problems involved in extrapolating from laboratory-derived toxicity data to field conditions make it impossible to regard a 1:1,500 ratio as a hard-and-fast figure. It should, rather, be regarded as a "best-guess" estimate of a safe level of dilution consistent with currently available information.

The 1:1,500 dilution ratio is based on the following considerations. The dilution factor necessary (NDF) to bring the concentration of a particular brine toxicant in produced water down to a safe level is given by the ratio of the concentration of the toxicant in produced water to the concentration of the pollutant that can be considered to have no significant toxicological effects. For example, it can be seen in Table A-1 that cadmium has been measured in produced water up to concentrations of 0.675 ppm. A toxicologically safe level for cadmium can be estimated (by application of a 0.01 factor to 96 hour LC50 data[13]) to be 0.0032 ppm. The ratio of 0.675 to 0.0032 is 210. Hence a dilution on the order of 210 parts water to 1 part produced water is necessary to bring the oilfield brine cadmium concentration down to a reasonably safe level, assuming an initial cadmium concentration in brine of 0.675 ppm. If considerable information is available concerning the effects of chronic exposure of organisms to low level toxicant concentrations, then this information can, of course, be used directly in determining a safe level rather than using the application factor approach.

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[13] The use of an application factor, commonly 0.01, to derive an estimate of a safe concentration level from 96 hour LC50 data for the most sensitive species likely to be affected is frequently recommended by the EPA as the basis for establishing quality criteria for water. See, for example, EPA Quality Criteria for Water, 1973, 1976.

To take into account the presence of several toxic substances, it is assumed that the effects are additive. To quote from the NAS-NAE report:[14]

> When two or more toxic materials are present at the same time in the receiving water, it should be assumed unless proven otherwise that their individual toxicities are additive and that some reduction in the permissible concentrations is necessary. The amount of reduction required is a function of both the number of toxic materials present and their concentrations in respect to the permissible concentrations. The following relationship will assure that the combined amounts of the several substances do not exceed a permissible concentration:
>
> $$\frac{C_a}{L_a} + \frac{C_b}{L_b} + \ldots + \frac{C_n}{L_n} \leq 1.0$$
>
> This formula may be applied where $C_a$, $C_b$, ... $C_n$ are the measured or expected concentrations of the several toxic materials in the water, and $L_a$, $L_b$, ... $L_n$ are the respective concentrations recommended or those derived by using recommended application factors on bioassays done under local conditions. Should the sum of the several fractions exceed 1.0, a local restriction on the concentration of one or more of the substances is necessary.

The above formula can easily be shown to be equivalent to summing the NDF's for each of the toxic constituents to obtain the total NDF needed for the brine. Thus, if $B_a$, $B_b$, ..., $B_n$ are the concentrations of the various toxicants in the undiluted brine, and N is a given level of dilution of the brine (i.e., N parts water to 1 part brine), then the concentrations of the brine toxicants in the diluted brine are simply

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[14] National Academy of Sciences and National Academy of Engineering, Water Quality Criteria, 1972, p. 122.

$$B_a/N,\ B_b/N,\ \ldots,\ B_n/N$$

But then it is required that these concentrations satisfy the above formula, or that

$$\frac{B_a/N}{L_a} + \frac{B_b/N}{L_b} + \ldots + \frac{B_n/N}{L_n} = \frac{1}{N}\left(\frac{B_a}{L_a} + \frac{B_b}{L_b} + \ldots + \frac{B_n}{L_n}\right) \leq 1.0$$

and hence

$$N \geq \frac{B_a}{L_a} + \frac{B_b}{L_b} + \ldots + \frac{B_n}{L_n}$$

Since $B_a/L_a$, $B_b/L_b$, etc. are the NDF's for the individual toxicants, we have the requirement that the NDF of the brine as a whole should be equal to or exceed the sum of the individual NDF's of the toxic brine constituents. If the NDF's for the individual brine toxicants are calculated starting with the reasonably conservative assumption that the initial concentration of a toxicant is the mean of the maximum concentrations tabulated in Table A-1, and the NDF's are then summed, a total NDF on the order of 1,500 is obtained.

That an estimate of 1,500:1 dilution is reasonable can be shown independently of the above calculation by referring to the fact that, as mentioned above, water soluble aromatic hydrocarbons may have sublethal effects on marine organisms at concentrations as low as 10 ppb.[15] Since the concentration of water soluble aromatic hydrocarbons in oilfield brines can be estimated to be 13.90 ppm (Table A-2), an NDF of approximately 13.90/0.01 or 1,390 is obtained for the aromatic water soluble fraction alone. This of course neglects consideration of the impacts of the non-aromatic water soluble fraction and the emulsified portion of the hydrocarbons present in oilfield brines, which can be expected to increase the NDF.

Assuming that a 1:1,500 (.066 percent) dilution of produced water results in toxicologically safe levels of the toxic constituents, a convenient measure of the impact associated with a given brine discharge is the area around the discharge point that can be expected to be subjected to produced waters at concentrations greater than or equal to .066 percent. It should be noted, however, that the 1:1,500 safe level is based on the mean of the maximum produced water contaminant concentrations which have been measured. Since data on contaminant levels in produced waters are sketchy, and since contaminant concentrations are highly variable, even between different sites in the same geographical region, "safe" levels at all sites will not necessarily occur at the 1:1,500 dilution level. It does, however, represent a reasonable estimate of safe concentrations for use in impact assessment.

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[15] Harrison et al., "Crude Oil Spills."

The area of the .066 percent dilution zone depends on a number of highly site-specific factors. Such factors include the rate at which produced water is discharged, the depth of the receiving water, currents (tidal, freshwater, drift), and diffusion coefficients. Other site-specific processes also affect contaminant dispersion but cannot be readily quantified. Processes in this category include adsorption of contaminants on suspended particles, sedimentation and transport of sediments, chemical transformation, and biodegradation. Severity of impact depends not only on the numerical size of the affected area but also on its ecology. Ecological characteristics are important in that they determine the value of the area being impacted in terms of the primary production the area supports, the commercially important species which live there, and the importance of the region to particular lifecycle stages of other economically or ecologically important organisms. Finally, impacts may also be evaluated in terms of the size of the impacted area relative to the size of the receiving waterbody. The same area may represent a much severer impact in a relatively small bay than in a larger, less enclosed water body.

As part of an Energy Resources Company study[16] of the proposed EPA regulations on offshore brine discharge, a computerized dispersion model[17] has been developed and used to estimate the areas at several discharge locations which would be subjected to average brine concentrations down to .066 percent dilution of the discharged brine. The site-specific factors of discharge rate, depth of receiving water, currents, and diffusion coefficients are incorporated into this model.[18] Four specific sites were studied. One, Hackberry Bay, Louisiana, is an enclosed, shallow (average depth equals 3 feet) coastal bay approximately 7 square miles in area. It is the location of a comparatively large brine discharge from the Bay de Chene oil field. The second location studied was the oilfield area of Cook Inlet, Alaska, which receives brine discharges from several production facilities. Both Hackberry Bay and Cook Inlet are classified as nearshore locations; i.e., they lie within the coastal baseline. EPA regulations have not yet been issued for nearshore discharges but they are expected to be similar to the regulations for near offshore discharges (i.e., waters between the coastal baseline and the 3-mile limit). For near offshore waters a site was chosen in the Grand Isle oil field, in Gulf of Mexico waters off of Grand Isle, Louisiana. For far offshore waters, a site was chosen in the Ship Shoal oil field in the Gulf of Mexico approximately 27 miles from the Louisiana shore. In all cases a level of treatment corresponding to the EPA BPCTCA regulations was assumed. Several sensitivity analyses were performed for each site in order to allow for uncertainties in available data on input parameter values and for simplifying assumptions incorporated into the model. The results of the computations for the four sites are summarized in Table A-4.

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[16] Energy Resources Co. Inc., Benefits Study of Effluent Limitations.

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[17] The dispersion model used in this study was originally developed by K. Stolzenbach and E. Adams at M.I.T. in their work on modeling thermal plume dispersion. It can be applied with equal validity to modeling the dispersion of any conservative dissolved substance discharged into a receiving waterbody. The model is described in detail both in the Energy Resources report (cited above) and in the following references: (1) E. Eric Adams, Keith D. Stolzenbach, and Donald Harleman, Near and Far Field Analysis of Buoyant Surface Discharges into Large Bodies of Water, Report No. 205, Ralph M. Parsons Laboratory, M.I.T., August, 1975; (2) Keith D. Stolzenbach et al., Analytical and Experimental Studies of Discharge Designs for the Cayuga Station at the Somerset Alternate Site, Report No. 211, Ralph M. Parsons Laboratory, M.I.T., May, 1976. The model is currently being used by Adams and Stolzenbach in their work on modeling the dispersion of brine discharge in connection with the FEA Strategic Petroleum Reserve program.

[18] A detailed discussion of the justification for the values used is given in the Energy Resources benefits study of offshore production effluent limitations referenced above.

An important conclusion to be drawn from the computations for Hackberry Bay and for Cook Inlet is the highly site-specific nature of the impacts in nearshore regions. In the case of Hackberry Bay, a large brine discharge combined with a relatively small diluting volume of water and sluggish flushing resulting from low tides and small freshwater flow gives a level equal to or greater than 0.1 percent brine concentration. Added to this is the fact that the bay is a highly productive area. Hence the impacts of brine discharge are significant. In mid Cook Inlet, on the other hand, not only is the available diluting volume far larger than it is in the case of Hackberry Bay, but the extremely vigorous tidal currents also serve to disperse pollutants over a large area so that concentrations fall off rapidly away from the discharge point. Ecologically, mid Cook Inlet has a rather low productivity as a result of tidal bottom scouring and high natural turbidity levels. Hence, the impacts of brine discharge into mid Cook Inlet do not appear to be the cause for concern.

As far as near offshore Gulf of Mexico waters are concerned, the computations performed for a single site are not sufficient to serve as a complete basis for estimating regional impacts. In order to extrapolate from impacts at a single platform to regional impacts, data on platform locations and discharge rates throughout the region are needed. However, a very rough estimate of total impacted area can be made based on the results in Table A-4. In order to obtain this estimate, it is assumed that impacted area varies linearly with the rate of discharge. The estimates of impacted areas given in Table A-4 for near offshore waters were based on a discharge rate of 1 cubic foot per second (equivalently, 26,930 gallons/hr or 15,390 bbl/day). Hence, to obtain an estimate of total impacted area, the total brine discharge rate in a region can be divided by 1 cubic foot per second and multiplied by the estimates of area impacted as a result of the 1 cubic foot per second discharge. An estimate of total oilfield brines discharged into near offshore Gulf of Mexico waters has been made by Sackett and Brooks.[19] They give a figure of 15 x $10^7$ liters/day or

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[19] W. Sackett and J. Brooks, "Origin and Distributions of Low Molecular Weight Hydrocarbons in Gulf of Mexico Coastal Waters," in Marine Chemistry in the Coastal Environment, ed. by T. Church, American Chemical Society Symposium Series 18, 1975.

TABLE A-4

## SUMMARY OF IMPACTS IN OFFSHORE AREAS

| SITE | LOCATION | PROBABLE AREA OF IMPACT ZONE | ECOLOGY |
|---|---|---|---|
| Hackberry Bay | Nearshore | Entire bay<br>(ca 192,000,000 $ft^2$)<br>(6.88 $mi^2$) | Highly productive, supports blue crab, panaeid shrimp, and other commercially important spp. |
| Cook Inlet | Nearshore | (ca. 5,000,000 $ft^2$)<br>(0.18 $mi^2$) | Relatively infertile due to continuous bottom scouring by tidal currents and to high turbidity |
| Grand Isle<br>(Gulf of Mexico) | Near Offshore | 400,000-4,700,000 $ft^2$<br>(.014-.17 $mi^2$) | Highly productive, supports several commercially important or sport species |
| Ship Shoal<br>(Gulf of Mexico) | Far Offshore | 2,000,000-4,000,000 $ft^2$<br>(.07-.14 $mi^2$) | Highly productive, supports several commercial or sport species |

Source: Energy Resources, Offshore Report, p. 8-4.

about 900,000 bbl/day. Dividing 900,000 by 15,390 gives a factor of approximately 60. The near offshore results in Table A-4 multiplied by 60 give an estimate of from 0.84 to 10.2 square miles of near offshore Gulf of Mexico waters adversely impacted as a result of the current level of brine discharge.

For far offshore Gulf of Mexico waters, the same comments hold regarding the estimation of regional impacts from the results given in Table A-4. For far offshore Gulf of Mexico waters, Sackett and Brooks given an estimate of 4.6 x $10^7$ liters/day or 274,000 bbl/day for the total brine discharge rate. Dividing by 15,390 as above gives a factor of 18 by which to multiply the estimates of impacted area given in Table A-4 for far offshore waters. The resulting estimate of total impacted area is from 1.3 to 2.6 square miles in far offshore Gulf of Mexico waters.

# APPENDIX B

## SUPPLY PRICES AND MARKET PRICES FOR PETROLEUM PRODUCTS

# APPENDIX B

## SUPPLY PRICES AND MARKET PRICES FOR PETROLEUM PRODUCTS

Assuming that the supply price of each refined product rises by the factor $(1 + \mu)$, consistent with approximately constant passthroughs of costs on the supply side, a simple linear market model is:

| | Before | After |
|---|---|---|
| Demand: | $q = \alpha + \beta p_1^d$ | $q = \alpha + \beta p_2^d$ |
| Supply: | $q = \gamma + \delta p_1^s$ | $q = \gamma + \delta (1 + \mu)^{-1} p_2^s$ |
| Market Clearing: | $p_1^d = p_1^s$ | $p_2^d = p_2^s$ |

where q is quantity and p is price (in real values).

The equilibrium prices ($p^e$) in these two situations are:

$$p_1^e = \frac{\alpha - \gamma}{\delta - \beta}$$

and

$$p_2^e = \frac{(1 + \mu)(\alpha - \gamma)}{\delta - \beta(1 + \mu)}$$

so that the proportional increase in market price consequent upon the given increase in supply price is:

$$\frac{\Delta p}{p} = \frac{p_2^e - p_1^e}{p_1^e} = \frac{\mu\delta}{\delta - \beta(1 + \mu)}$$

As the variables are measured in logarithmic units, only the price elasticities of demand ($\beta$) and supply ($\delta$) influence the degree of passthrough of supply price increases onto market prices.

It can be seen that:

$$\underset{\beta\to 0}{\text{Limit}}\left(\frac{\Delta p}{p}\right) = \mu$$

and

$$\underset{\beta\to\infty}{\text{Limit}}\left(\frac{\Delta p}{p}\right) = 0$$

while

$$\underset{\delta\to 0}{\text{Limit}}\left(\frac{\Delta p}{p}\right) = 0$$

and

$$\underset{\delta\to\infty}{\text{Limit}}\left(\frac{\Delta p}{p}\right) = \mu$$

and

$$0 \leq \frac{\Delta p}{p} \leq \mu$$

for $\mu > 0$.

The importance of the supply elasticity can be illustrated geometrically (Figure B-1). The upward shift in the supply curve for the specific product by a factor of $(1 + \mu)$ from $S_1$ to $S_2$ creates excess supply equal to (ab) at the new supply price. Sellers, therefore, accept a smaller price increase, which, by stimulating supply and reducing demand, eventually eliminates the excess supply. If the supply curve is price-inelastic, as implied in the production analysis ($\delta = 0.18$ comparing Base Case and Stage II production levels), market prices rise only slightly, from $p_1^e$ to $p_2^e$. If, however, the ability of the oil companies to restrict competition is substantial,[1] the price elasticity of supply in the downward direction may be much greater than in the upward one ($S_1'$ and $S_2'$). The new equilibrium price $p_2^{e'}$ is correspondingly greater.

---

[1] If it were total, as in the cartel, the concept of a supply curve itself would become invalid.

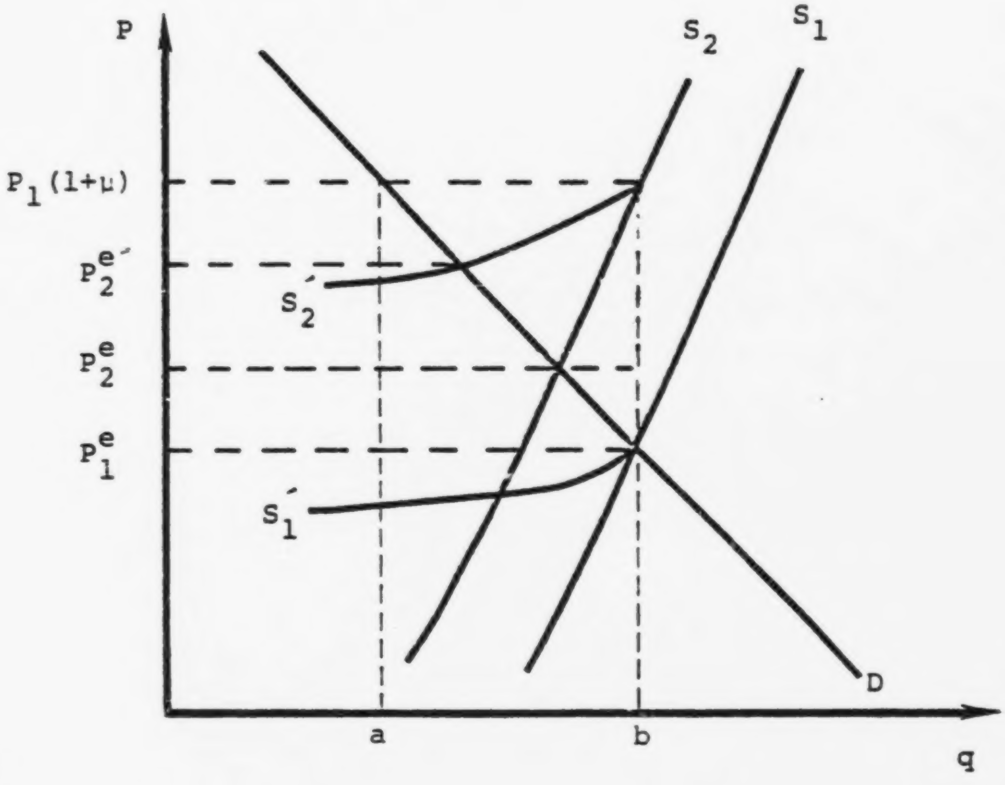

Figure B-1. Supply elasticities and market prices.

Accordingly, a discontinuity in supply elasticity at prevailing market prices will be assumed, and a middling value ($\delta = 1$) assigned to the supply elasticity for movements down the supply curve.

# APPENDIX C

## RESIDUAL LOADINGS FROM OIL PRODUCTION BY PETROLEUM SUPPLY REGION AND BY METHOD OF RECOVERY FOR EACH ALTERNATIVE PRICING POLICY

# APPENDIX C

## RESIDUAL LOADINGS FROM OIL PRODUCTION BY PETROLEUM SUPPLY REGION AND BY METHOD OF RECOVERY FOR EACH ALTERNATIVE PRICING POLICY

The 36 tables in this appendix show the preliminary information that is input to the Environmental Residual Allocation Model developed for Project Independence[1] and subsequently modified to include the impacts of tertiary oil recovery. The tables are of two forms. There are 18 tables of each form corresponding to 1975, the 16 alternatives for 1979, and 1985. The first form (Tables C-1 to C-18) shows levels of residuals generated by oil production for each Petroleum Supply Region (see Figure C-1). The second form (Tables C-19 to C-36) shows national residual loadings from oil production by method of recovery. In addition to providing input to the environmental assessment model, these tables provide in themselves in summary fashion information on the regional and technological environmental implications of oil production under the alternative pricing policies.

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[1] Energy Resources Company Inc., Assessment of the Environmental Implications of Project Independence, prepared for the U.S. Environmental Protection Agency, July 1976.

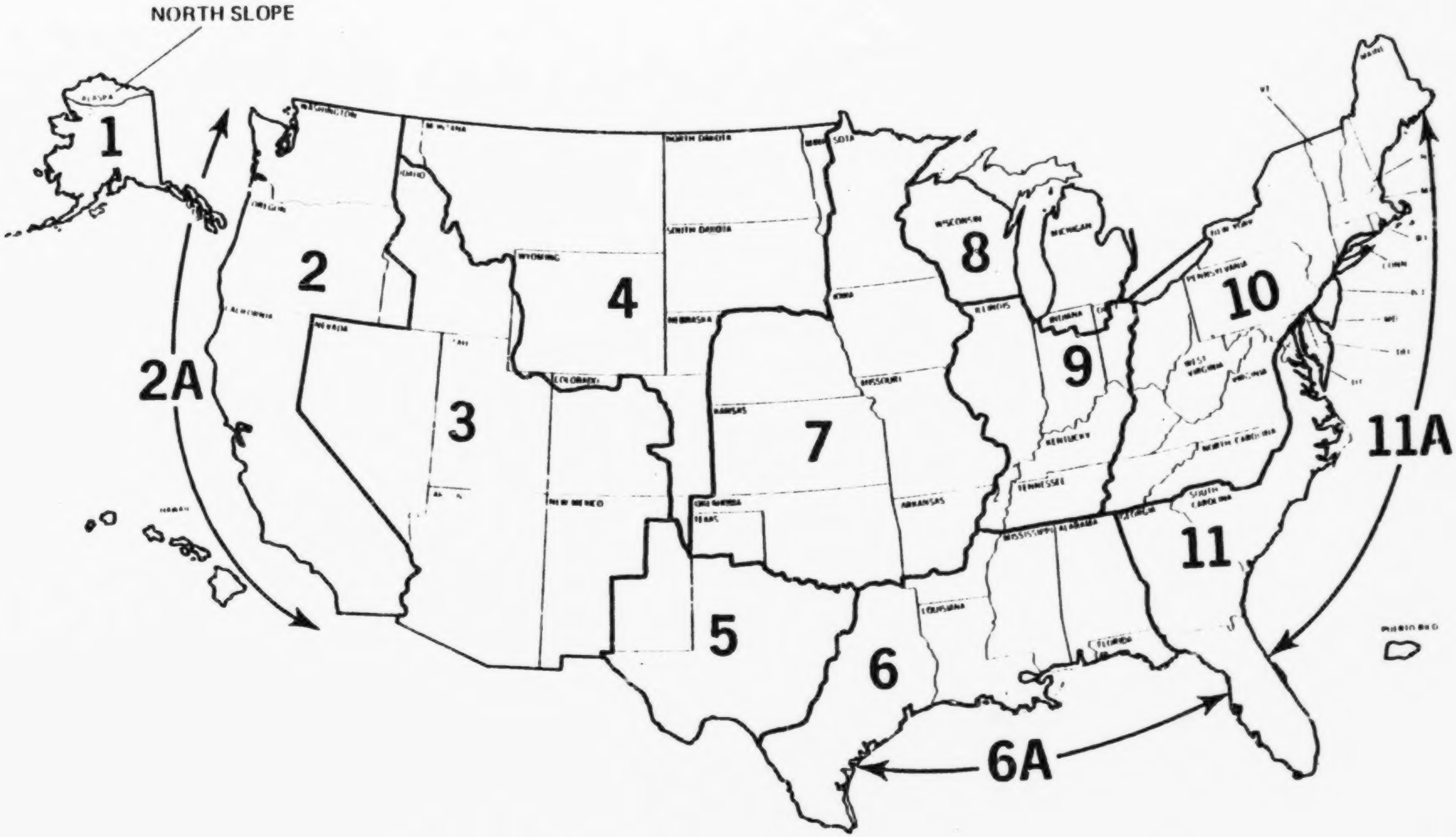
NORTH SLOPE
1
2A
2
3
4
5
6
6A
7
8
9
10
11
11A

Figure C-1. Petroleum Provinces of the United States.

## TABLE C-1

## REGIONAL POLLUTION LOADINGS FROM OIL PRODUCTION

## 1975

| NPC REGION | PRODUCTION (1,000 bbls/ day) | ORGANICS (100 tons/ day) | PARTI-CULATES (tons/day) | NOx (tons/day) | SOx (tons/day) | HYDRO-CARBONS (tons/day) | CARBON MONOXIDE (tons/day) | FIXED LAND (100 acres) |
|---|---|---|---|---|---|---|---|---|
| North Slope | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 1 | 190 | 0.04807 | 0 | 0 | 0 | 0 | 0 | 4.598 |
| 2 | 670 | 0.019564 | 14.4 | 87.12 | 196.2 | 2.88 | 0.576 | 139.36 |
| 2A | 220 | 0.05566 | 0 | 0 | 0 | 0 | 0 | 5.324 |
| 3 | 140 | 0.004088 | 0 | 0 | 0 | 0 | 0 | 29.12 |
| 4 | 620 | 0.018104 | 0 | 0 | 0 | 0 | 0 | 128.96 |
| 5 | 2050 | 0.05936 | 0 | 0 | 0 | 0 | 0 | 426.4 |
| 6 | 2440 | 0.071248 | 0 | 0 | 0 | 6.35 | 31.25 | 507.52 |
| 6A | 990 | 0.25047 | 0 | 0 | 0 | 0 | 0 | 23.958 |
| 7 | 730 | 0.021316 | 0 | 0 | 0 | 0 | 0 | 151.84 |
| 8-9-10 | 220 | 0.006424 | 0 | 0 | 0 | 0 | 0 | 45.76 |
| 11 | 110 | 0.003212 | 0 | 0 | 0 | 0 | 0 | 22.88 |
| 11A | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| National Totals | 8380 | 0.558016 | 14.4 | 87.12 | 196.2 | 9.23 | 31.826 | 1485.72 |

# TABLE C-2

## REGIONAL POLLUTION LOADINGS FROM OIL PRODUCTION

### BASE CASE
### (1979)

| NPC REGION | PRODUCTION (1,000 bbls/ day) | ORGANICS (100 tons/ day) | PARTI- CULATES (tons/day) | NOx (tons/day) | SOx (tons/day) | HYDRO- CARBONS (tons/day) | CARBON MONOXIDE (tons/day) | FIXED LAND (100 acres) |
|---|---|---|---|---|---|---|---|---|
| North Slope | 1420 | 0.041464 | 0 | 0 | 0 | 0 | 0 | 295.36 |
| 1 | 120 | 0.03036 | 0 | 0 | 0 | 0 | 0 | 2.904 |
| 2 | 990 | 0.028908 | 13.6 | 82.28 | 185.3 | 2.72 | 0.544 | 205.92 |
| 2A | 90 | 0.02277 | 0 | 0 | 0 | 0 | 0 | 2.178 |
| 3 | 180 | 0.005256 | 0 | 0 | 0 | 0 | 0 | 37.44 |
| 4 | 470 | 0.013724 | 0 | 0 | 0 | 0 | 0 | 97.76 |
| 5 | 1660 | 0.048472 | 0 | 0 | 0 | 0 | 0 | 345.28 |
| 6 | 2630 | 0.076796 | 0 | 0 | 0 | 12.7 | 62.5 | 547.04 |
| 6A | 1350 | 0.34155 | 0 | 0 | 0 | 0 | 0 | 32.67 |
| 7 | 520 | 0.015184 | 0 | 0 | 0 | 0 | 0 | 108.16 |
| 8-9-10 | 160 | 0.004672 | 0 | 0 | 0 | 0 | 0 | 33.28 |
| 11 | 100 | 0.00292 | 0 | 0 | 0 | 0 | 0 | 20.8 |
| 11A | 60 | 0.01518 | 0 | 0 | 0 | 0 | 0 | 1.452 |
| National Totals | 9750 | 0.647256 | 13.6 | 82.28 | 185.3 | 15.42 | 63.044 | 1730.24 |

## TABLE C-3

## REGIONAL POLLUTION LOADINGS FROM OIL PRODUCTION

IIA
(1979)

| NPC REGION | PRODUCTION (1,000 bbls/ day) | ORGANICS (100 tons/ day) | PARTI-CULATES (tons/day) | NOx (tons/day) | SOx (tons/day) | HYDRO-CARBONS (tons/day) | CARBON MONOXIDE (tons/day) | FIXED LAND (100 acres) |
|---|---|---|---|---|---|---|---|---|
| North Slope | 1420 | 0.041464 | 0 | 0 | 0 | 0 | 0 | 295.36 |
| 1 | 120 | 0.03036 | 0 | 0 | 0 | 0 | 0 | 2.904 |
| 2 | 1050 | 0.03066 | 13.6 | 82.28 | 185.3 | 28.12 | 125.544 | 218.4 |
| 2A | 160 | 0.04048 | 0 | 0 | 0 | 0 | 0 | 3.872 |
| 3 | 180 | 0.005256 | 0 | 0 | 0 | 0 | 0 | 37.44 |
| 4 | 540 | 0.015768 | 0 | 0 | 0 | 0 | 0 | 112.32 |
| 5 | 1690 | 0.049348 | 0 | 0 | 0 | 0 | 0 | 351.52 |
| 6 | 2980 | 0.087016 | 0 | 0 | 0 | 25.4 | 125 | 619.84 |
| 6A | 1390 | 0.35167 | 0 | 0 | 0 | 0 | 0 | 33.638 |
| 7 | 560 | 0.016352 | 0 | 0 | 0 | 0 | 0 | 116.48 |
| 8-9-10 | 210 | 0.006132 | 0 | 0 | 0 | 0 | 0 | 43.68 |
| 11 | 100 | 0.00292 | 0 | 0 | 0 | 0 | 0 | 20.8 |
| 11A | 60 | 0.01518 | 0 | 0 | 0 | 0 | 0 | 1.452 |
| National Totals | 10460 | 0.692606 | 13.6 | 82.28 | 185.3 | 53.52 | 250.544 | 1857.71 |

## TABLE C-4

## REGIONAL POLLUTION LOADINGS FROM OIL PRODUCTION

### IIB
### (1979)

| NPC REGION | PRODUCTION (1,000 bbls/ day) | ORGANICS (100 tons/ day) | PARTI- CULATES (tons/day) | NOx (tons/day) | SOx (tons/day) | HYDRO- CARBONS (tons/day) | CARBON MONOXIDE (tons/day) | FIXED LAND (100 acres) |
|---|---|---|---|---|---|---|---|---|
| North Slope | 1420 | 0.041464 | 0 | 0 | 0 | 0 | 0 | 295.36 |
| 1 | 120 | 0.03036 | 0 | 0 | 0 | 0 | 0 | [illegible] |
| 2 | 1060 | 0.030952 | 14.4 | 87.12 | 196.2 | 28.28 | 125.576 | 220.48 |
| 2A | 160 | 0.04048 | 0 | 0 | 0 | 0 | 0 | [illegible] |
| 3 | 180 | 0.005256 | 0 | 0 | 0 | 0 | 0 | 37.44 |
| 4 | 540 | 0.015768 | 0 | 0 | 0 | 0 | 0 | 112.32 |
| 5 | 1690 | 0.049348 | 0 | 0 | 0 | 0 | 0 | 351.52 |
| 6 | 2980 | 0.087016 | 0 | 0 | 0 | 25.4 | 125 | 619.84 |
| 6A | 1390 | 0.35167 | 0 | 0 | 0 | 0 | 0 | [illegible] |
| 7 | 560 | 0.016352 | 0 | 0 | 0 | 0 | 0 | 116.48 |
| 8-9-10 | 210 | 0.006132 | 0 | 0 | 0 | 0 | 0 | 43.68 |
| 11 | 100 | 0.00292 | 0 | 0 | 0 | 0 | 0 | 20.8 |
| 11A | 60 | 0.01518 | 0 | 0 | 0 | 0 | 0 | [illegible] |
| National Totals | 10470 | 0.692898 | 14.4 | 87.12 | 196.2 | 53.68 | 250.576 | [illegible] |

## TABLE C-5

## REGIONAL POLLUTION LOADINGS FROM OIL PRODUCTION

IIC
(1979)

| NPC REGION | PRODUCTION (1,000 bbls/day) | ORGANICS (100 tons/day) | PARTI-CULATES (tons/day) | NOx (tons/day) | SOx (tons/day) | HYDRO-CARBONS (tons/day) | CARBON MONOXIDE (tons/day) | FIXED LAND (100 acres) |
|---|---|---|---|---|---|---|---|---|
| North Slope | 1420 | 0.041464 | 0 | 0 | 0 | 0 | 0 | 295.36 |
| 1 | 120 | 0.03036 | 0 | 0 | 0 | 0 | 0 | 2.904 |
| 2 | 1020 | 0.029784 | 13.6 | 82.28 | 185.3 | 2.72 | 0.544 | 212.16 |
| 2A | 160 | 0.04048 | 0 | 0 | 0 | 0 | 0 | 3.872 |
| 3 | 180 | 0.005256 | 0 | 0 | 0 | 0 | 0 | 37.44 |
| 4 | 540 | 0.015768 | 0 | 0 | 0 | 0 | 0 | 112.32 |
| 5 | 1670 | 0.048764 | 0 | 0 | 0 | 0 | 0 | 347.36 |
| 6 | 2950 | 0.08614 | 0 | 0 | 0 | 12.7 | 62.5 | 613.6 |
| 6A | 1390 | 0.35167 | 0 | 0 | 0 | 0 | 0 | 33.638 |
| 7 | 560 | 0.016352 | 0 | 0 | 0 | 0 | 0 | 116.48 |
| 8-9-10 | 210 | 0.006132 | 0 | 0 | 0 | 0 | 0 | 43.68 |
| 11 | 100 | 0.00292 | 0 | 0 | 0 | 0 | 0 | 20.8 |
| 11A | 60 | 0.01518 | 0 | 0 | 0 | 0 | 0 | 1.452 |
| National Totals | 10380 | 0.69029 | 13.6 | 82.28 | 185.3 | 15.42 | 63.044 | 1841.07 |

## TABLE C-6

## REGIONAL POLLUTION LOADINGS FROM OIL PRODUCTION

IIA IIIA
(1979)

| NPC REGION | PRODUCTION (1,000 bbls/ day) | ORGANICS (100 tons/ day) | PARTI-CULATES (tons/day) | NOx (tons/day) | SOx (tons/day) | HYDRO-CARBONS (tons/day) | CARBON MONOXIDE (tons/day) | FIXED LAND (100 acres) |
|---|---|---|---|---|---|---|---|---|
| North Slope | 1420 | 0.041464 | 0 | 0 | 0 | 0 | 0 | 295.36 |
| 1 | 120 | 0.03036 | 0 | 0 | 0 | 0 | 0 | 2.904 |
| 2 | 1110 | 0.032412 | 16.8 | 101.64 | 228.9 | 41.46 | 188.172 | 230.88 |
| 2A | 160 | 0.04048 | 0 | 0 | 0 | 0 | 0 | 3.872 |
| 3 | 180 | 0.005256 | 0 | 0 | 0 | 0 | 0 | 37.44 |
| 4 | 540 | 0.015768 | 0 | 0 | 0 | 0 | 0 | 112.32 |
| 5 | 1750 | 0.0511 | 0 | 0 | 0 | 0 | 0 | 364. |
| 6 | 2960 | 0.086432 | 0 | 0 | 0 | 38.1 | 187.5 | 615.68 |
| 6A | 1380 | 0.34914 | 0 | 0 | 0 | 0 | 0 | 33.396 |
| 7 | 540 | 0.015768 | 0 | 0 | 0 | 0 | 0 | 112.32 |
| 8-9-10 | 210 | 0.006132 | 0 | 0 | 0 | 0 | 0 | 43.68 |
| 11 | 100 | 0.00292 | 0 | 0 | 0 | 0 | 0 | 20.8 |
| 11A | 60 | 0.01518 | 0 | 0 | 0 | 0 | 0 | 1.452 |
| National Totals | 10530 | 0.692412 | 16.8 | 101.64 | 228.5 | 79.56 | 375.672 | 1874.1 |

# TABLE C-7

## REGIONAL POLLUTION LOADINGS FROM OIL PRODUCTION

IIB IIIA
(1979)

| NPC REGION | PRODUCTION (1,000 bbls/ day) | ORGANICS (100 tons/ day) | PARTI- CULATES (tons/day) | NOx (tons/day) | SOx (tons/day) | HYDRO- CARBONS (tons/day) | CARBON MONOXIDE (tons/day) | FIXED LAND (100 acres) |
|---|---|---|---|---|---|---|---|---|
| North Slope | 1420 | 0.041464 | 0 | 0 | 0 | 0 | 0 | 295.36 |
| 1 | 120 | 0.03036 | 0 | 0 | 0 | 0 | 0 | 2.904 |
| 2 | 1110 | 0.032412 | 16.8 | 101.64 | 228.9 | 41.46 | 188.172 | 230.88 |
| 2A | 160 | 0.04048 | 0 | 0 | 0 | 0 | 0 | 3.872 |
| 3 | 180 | 0.005256 | 0 | 0 | 0 | 0 | 0 | 37.44 |
| 4 | 540 | 0.015768 | 0 | 0 | 0 | 0 | 0 | 112.32 |
| 5 | 1750 | 0.0511 | 0 | 0 | 0 | 0 | 0 | 364. |
| 6 | 2910 | 0.084972 | 0 | 0 | 0 | 38.1 | 187.5 | 605.28 |
| 6A | 1380 | 0.34914 | 0 | 0 | 0 | 0 | 0 | 33.396 |
| 7 | 530 | 0.015476 | 0 | 0 | 0 | 0 | 0 | 110.24 |
| 8-9-10 | 210 | 0.006132 | 0 | 0 | 0 | 0 | 0 | 43.68 |
| 11 | 100 | 0.00292 | 0 | 0 | 0 | 0 | 0 | 20.8 |
| 11A | 60 | 0.01518 | 0 | 0 | 0 | 0 | 0 | 1.452 |
| National Totals | 10470 | 0.69066 | 16.8 | 101.64 | 228.9 | 79.56 | 375.672 | 1861.62 |

# TABLE C-8

## REGIONAL POLLUTION LOADINGS FROM OIL PRODUCTION

IIC IIIA
(1979)

| NPC REGION | PRODUCTION (1,000 bbls/ day) | ORGANICS (100 tons/ day) | PARTI- CULATES (tons/day) | NOx (tons/day) | SOx (tons/day) | HYDRO- CARBONS (tons/day) | CARBON MONOXIDE (tons/day) | FIXED LAND (100 acres) |
|---|---|---|---|---|---|---|---|---|
| North Slope | 1420 | 0.041464 | 0 | 0 | 0 | 0 | 0 | 295.36 |
| 1 | 120 | 0.03036 | 0 | 0 | 0 | 0 | 0 | 2.904 |
| 2 | 1110 | 0.032412 | 16.8 | 101.64 | 228.9 | 41.46 | 188.172 | 230.88 |
| 2A | 160 | 0.04048 | 0 | 0 | 0 | 0 | 0 | 3.872 |
| 3 | 180 | 0.005256 | 0 | 0 | 0 | 0 | 0 | 37.44 |
| 4 | 540 | 0.015768 | 0 | 0 | 0 | 0 | 0 | 112.32 |
| 5 | 1750 | 0.0511 | 0 | 0 | 0 | 0 | 0 | 364. |
| 6 | 3030 | 0.088476 | 0 | 0 | 0 | 38.1 | 187.5 | 630.24 |
| 6A | 1390 | 0.35167 | 0 | 0 | 0 | 0 | 0 | 33.638 |
| 7 | 560 | 0.016352 | 0 | 0 | 0 | 0 | 0 | 116.48 |
| 8-9-10 | 210 | 0.006132 | 0 | 0 | 0 | 0 | 0 | 43.68 |
| 11 | 100 | 0.00292 | 0 | 0 | 0 | 0 | 0 | 20.8 |
| 11A | 60 | 0.01518 | 0 | 0 | 0 | 0 | 0 | 1.452 |
| National Totals | 10630 | 0.69757 | 16.8 | 101.64 | 228.9 | 79.56 | 375.672 | 1893.07 |

## TABLE C-9

## REGIONAL POLLUTION LOADINGS FROM OIL PRODUCTION

IIA IIIB
(1979)

| NPC REGION | PRODUCTION (1,000 bbls/day) | ORGANICS (100 tons/day) | PARTI-CULATES (tons/day) | NOx (tons/day) | SOx (tons/day) | HYDRO-CARBONS (tons/day) | CARBON MONOXIDE (tons/day) | FIXED LAND (100 acres) |
|---|---|---|---|---|---|---|---|---|
| North Slope | 1420 | 0.041464 | 0 | 0 | 0 | 0 | 0 | 295.36 |
| 1 | 120 | 0.03036 | 0 | 0 | 0 | 0 | 0 | 2.904 |
| 2 | 1120 | 0.032704 | 16.8 | 101.64 | 228.9 | 41.46 | 188.172 | 232.96 |
| 2A | 160 | 0.04048 | 0 | 0 | 0 | 0 | 0 | 3.872 |
| 3 | 180 | 0.005256 | 0 | 0 | 0 | 0 | 0 | 37.44 |
| 4 | 540 | 0.015768 | 0 | 0 | 0 | 0 | 0 | 112.32 |
| 5 | 1780 | 0.051976 | 0 | 0 | 0 | 0 | 0 | 370.24 |
| 6 | 2890 | 0.084388 | 0 | 0 | 0 | 38.1 | 187.5 | 601.12 |
| 6A | 1370 | 0.34661 | 0 | 0 | 0 | 0 | 0 | 33.154 |
| 7 | 520 | 0.015184 | 0 | 0 | 0 | 0 | 0 | 108.16 |
| 8-9-10 | 210 | 0.006132 | 0 | 0 | 0 | 0 | 0 | 43.68 |
| 11 | 100 | 0.00292 | 0 | 0 | 0 | 0 | 0 | 20.8 |
| 11A | 60 | 0.01518 | 0 | 0 | 0 | 0 | 0 | 1.452 |
| National Totals | 10470 | 0.688422 | 16.8 | 101.64 | 228.9 | 79.56 | 375.672 | 1863.46 |

## TABLE C-10

## REGIONAL POLLUTION LOADINGS FROM OIL PRODUCTION

IIB IIIB
(1979)

| NPC REGION | PRODUCTION (1,000 bbls/ day) | ORGANICS (100 tons/ day) | PARTI- CULATES (tons/day) | NOx (tons/day) | SOx (tons/day) | HYDRO- CARBONS (tons/day) | CARBON MONOXIDE (tons/day) | FIXED LAND (100 acres) |
|---|---|---|---|---|---|---|---|---|
| North Slope | 1420 | 0.041464 | 0 | 0 | 0 | 0 | 0 | 295.36 |
| 1 | 120 | 0.03036 | 0 | 0 | 0 | 0 | 0 | 2.904 |
| 2 | 1120 | 0.032704 | 16.8 | 101.64 | 228.9 | 41.46 | 188.172 | 232.96 |
| 2A | 160 | 0.04048 | 0 | 0 | 0 | 0 | 0 | 3.872 |
| 3 | 180 | 0.005256 | 0 | 0 | 0 | 0 | 0 | 37.44 |
| 4 | 540 | 0.015768 | 0 | 0 | 0 | 0 | 0 | 112.32 |
| 5 | 1780 | 0.051976 | 0 | 0 | 0 | 0 | 0 | 370.24 |
| 6 | 2830 | 0.082636 | 0 | 0 | 0 | 38.1 | 187.5 | 588.64 |
| 6A | 1360 | 0.34408 | 0 | 0 | 0 | 0 | 0 | 32.912 |
| 7 | 520 | 0.015184 | 0 | 0 | 0 | 0 | 0 | 108.16 |
| 8-9-10 | 210 | 0.006132 | 0 | 0 | 0 | 0 | 0 | 43.68 |
| 11 | 100 | 0.00292 | 0 | 0 | 0 | 0 | 0 | 20.8 |
| 11A | 60 | 0.01518 | 0 | 0 | 0 | 0 | 0 | 1.452 |
| National Totals | 10400 | 0.68414 | 16.8 | 101.64 | 228.9 | 79.56 | 375.672 | 1850.74 |

## TABLE C-11

## REGIONAL POLLUTION LOADINGS FROM OIL PRODUCTION

IIC IIIB
(1979)

| NPC REGION | PRODUCTION (1,000 bbls/ day) | ORGANICS (100 tons/ day) | PARTI- CULATES (tons/day) | NOx (tons/day) | SOx (tons/day) | HYDRO- CARBONS (tons/day) | CARBON MONOXIDE (tons/day) | FIXED LAND (100 acres) |
|---|---|---|---|---|---|---|---|---|
| North Slope | 1420 | 0.041464 | 0 | 0 | 0 | 0 | 0 | 295.36 |
| 1 | 120 | 0.03036 | 0 | 0 | 0 | 0 | 0 | 2.904 |
| 2 | 1120 | 0.032704 | 16.8 | 101.64 | 228.9 | 41.46 | 188.172 | 232.96 |
| 2A | 160 | 0.04048 | 0 | 0 | 0 | 0 | 0 | 3.872 |
| 3 | 180 | 0.005256 | 0 | 0 | 0 | 0 | 0 | 37.44 |
| 4 | 540 | 0.015768 | 0 | 0 | 0 | 0 | 0 | 112.32 |
| 5 | 1780 | 0.051976 | 0 | 0 | 0 | 0 | 0 | 370.24 |
| 6 | 2970 | 0.086724 | 0 | 0 | 0 | 38.1 | 187.5 | 617.76 |
| 6A | 1380 | 0.34914 | 0 | 0 | 0 | 0 | 0 | 35.396 |
| 7 | 540 | 0.015768 | 0 | 0 | 0 | 0 | 0 | 112.32 |
| 8-9-10 | 210 | 0.006132 | 0 | 0 | 0 | 0 | 0 | 43.68 |
| 11 | 100 | 0.00292 | 0 | 0 | 0 | 0 | 0 | 20.8 |
| 11A | 60 | 0.01518 | 0 | 0 | 0 | 0 | 0 | 1.452 |
| National Totals | 10580 | 0.693872 | 16.8 | 101.64 | 228.9 | 79.56 | 375.672 | 1884.5 |

## TABLE C-12

## REGIONAL POLLUTION LOADINGS FROM OIL PRODUCTION

IIA IIIC
(1979)

| NPC REGION | PRODUCTION (1,000 bbls/ day) | ORGANICS (100 tons/ day) | PARTI- CULATES (tons/day) | NOx (tons/day) | SOx (tons/day) | HYDRO- CARBONS (tons/day) | CARBON MONOXIDE (tons/day) | FIXED LAND (100 acres) |
|---|---|---|---|---|---|---|---|---|
| North Slope | 1420 | 0.041464 | 0 | 0 | 0 | 0 | 0 | 295.36 |
| 1 | 120 | 0.03036 | 0 | 0 | 0 | 0 | 0 | 2.904 |
| 2 | 1050 | 0.03066 | 13.6 | 82.28 | 185.3 | 28.12 | 125.544 | 218.4 |
| 2A | 160 | 0.04048 | 0 | 0 | 0 | 0 | 0 | 3.872 |
| 3 | 180 | 0.005256 | 0 | 0 | 0 | 0 | 0 | 37.44 |
| 4 | 540 | 0.015768 | 0 | 0 | 0 | 0 | 0 | 112.32 |
| 5 | 1690 | 0.049348 | 0 | 0 | 0 | 0 | 0 | 351.52 |
| 6 | 2980 | 0.087016 | 0 | 0 | 0 | 25.4 | 125 | 619.84 |
| 6A | 1420 | 0.35926 | 0 | 0 | 0 | 0 | 0 | 34.864 |
| 7 | 560 | 0.016352 | 0 | 0 | 0 | 0 | 0 | 116.48 |
| 8-9-10 | 210 | 0.006132 | 0 | 0 | 0 | 0 | 0 | 43.68 |
| 11 | 100 | 0.00292 | 0 | 0 | 0 | 0 | 0 | 20.8 |
| 11A | 60 | 0.01518 | 0 | 0 | 0 | 0 | 0 | 1.452 |
| National Totals | 10490 | 0.700196 | 13.6 | 82.28 | 185.3 | 53.52 | 250.544 | 1858.43 |

## TABLE C-13

## REGIONAL POLLUTION LOADINGS FROM OIL PRODUCTION

IIB IIIC
(1979)

| NPC REGION | PRODUCTION (1,000 bbls/day) | ORGANICS (100 tons/day) | PARTI-CULATES (tons/day) | NOx (tons/day) | SOx (tons/day) | HYDRO-CARBONS (tons/day) | CARBON MONOXIDE (tons/day) | FIXED LAND (100 acres) |
|---|---|---|---|---|---|---|---|---|
| North Slope | 1420 | 0.041464 | 0 | 0 | 0 | 0 | 0 | 295.36 |
| 1 | 120 | 0.03036 | 0 | 0 | 0 | 0 | 0 | 2.904 |
| 2 | 1060 | 0.030952 | 14.4 | 87.12 | 196.2 | 28.28 | 125.576 | 220.48 |
| 2A | 160 | 0.04048 | 0 | 0 | 0 | 0 | 0 | 3.872 |
| 3 | 180 | 0.005256 | 0 | 0 | 0 | 0 | 0 | 37.44 |
| 4 | 540 | 0.015768 | 0 | 0 | 0 | 0 | 0 | 112.32 |
| 5 | 1640 | 0.049348 | 0 | 0 | 0 | 0 | 0 | 351.52 |
| 6 | 2980 | 0.087016 | 0 | 0 | 0 | 25.4 | 125 | 619.84 |
| 6A | 1426 | 0.35926 | 0 | 0 | 0 | 0 | 0 | 34.364 |
| 7 | 560 | 0.016352 | 0 | 0 | 0 | 0 | 0 | 116.48 |
| 8-9-10 | 210 | 0.006132 | 0 | 0 | 0 | 0 | 0 | 43.68 |
| 11 | 100 | 0.002952 | 0 | 0 | 0 | 0 | 0 | 20.8 |
| 11A | 60 | 0.01518 | 0 | 0 | 0 | 0 | 0 | 1.452 |
| National Totals | 10500 | 0.700488 | 14.4 | 87.12 | 196.2 | 53.68 | 250.576 | 1860.51 |

# TABLE C-14

## REGIONAL POLLUTION LOADINGS FROM OIL PRODUCTION

IIC IIIC
(1979)

| NPC REGION | PRODUCTION (1,000 bbls/day) | ORGANICS (100 tons/day) | PARTI-CULATES (tons/day) | NOx (tons/day) | SOx (tons/day) | HYDRO-CARBONS (tons/day) | CARBON MONOXIDE (tons/day) | FIXED LAND (100 acres) |
|---|---|---|---|---|---|---|---|---|
| North Slope | 1420 | 0.041464 | 0 | 0 | 0 | 0 | 0 | 295.36 |
| 1 | 120 | 0.03036 | 0 | 0 | 0 | 0 | 0 | 2.904 |
| 2 | 1020 | 0.029784 | 13.6 | 82.28 | 185.3 | 2.72 | 0.544 | 212.16 |
| 2A | 160 | 0.04048 | 0 | 0 | 0 | 0 | 0 | 3.872 |
| 3 | 180 | 0.005256 | 0 | 0 | 0 | 0 | 0 | 37.44 |
| 4 | 540 | 0.015768 | 0 | 0 | 0 | 0 | 0 | 112.32 |
| 5 | 1670 | 0.048764 | 0 | 0 | 0 | 0 | 0 | 347.36 |
| 6 | 2950 | 0.08614 | 0 | 0 | 0 | 12.7 | 62.5 | 613.6 |
| 6A | 1420 | 0.35926 | 0 | 0 | 0 | 0 | 0 | 34.364 |
| 7 | 560 | 0.016352 | 0 | 0 | 0 | 0 | 0 | 116.48 |
| 8-9-10 | 210 | 0.006132 | 0 | 0 | 0 | 0 | 0 | 43.68 |
| 11 | 100 | 0.00292 | 0 | 0 | 0 | 0 | 0 | 20.8 |
| 11A | 60 | 0.01518 | 0 | 0 | 0 | 0 | 0 | 1.452 |
| National Totals | 10410 | 0.69786 | 13.6 | 82.28 | 185.3 | 15.42 | 63.044 | 1841.79 |

## TABLE C-15

## REGIONAL POLLUTION LOADINGS FROM OIL PRODUCTION

IIA IIID
(1979)

| NPC REGION | PRODUCTION (1,000 bbls/day) | ORGANICS (100 tons/day) | PARTI-CULATES (tons/day) | NOx (tons/day) | SOx (tons/day) | HYDRO-CARBONS (tons/day) | CARBON MONOXIDE (tons/day) | FIXED LAND (100 acres) |
|---|---|---|---|---|---|---|---|---|
| North Slope | 1420 | 0.041464 | 0 | 0 | 0 | 0 | 0 | 295.36 |
| 1 | 120 | 0.03036 | 0 | 0 | 0 | 0 | 0 | 2.904 |
| 2 | 1070 | 0.031244 | 13.6 | 82.28 | 185.3 | 28.12 | 125.544 | 222.56 |
| 2A | 160 | 0.04048 | 0 | 0 | 0 | 0 | 0 | 3.872 |
| 3 | 180 | 0.005256 | 0 | 0 | 0 | 0 | 0 | 27.44 |
| 4 | 540 | 0.015768 | 0 | 0 | 0 | 0 | 0 | 112.32 |
| 5 | 1690 | 0.049348 | 0 | 0 | 0 | 0 | 0 | 351.52 |
| 6 | 2980 | 0.087016 | 0 | 0 | 0 | 25.4 | 125 | 619.84 |
| 6A | 1390 | 0.35167 | 0 | 0 | 0 | 0 | 0 | 33.638 |
| 7 | 560 | 0.016352 | 0 | 0 | 0 | 0 | 0 | 116.48 |
| 8-9-10 | 210 | 0.006132 | 0 | 0 | 0 | 0 | 0 | 43.68 |
| 11 | 100 | 0.00292 | 0 | 0 | 0 | 0 | 0 | 20.8 |
| 11A | 60 | 0.01518 | 0 | 0 | 0 | 0 | 0 | 1.452 |
| National Totals | 10480 | 0.69310 | 13.6 | 82.28 | 185.3 | 53.52 | 250.544 | 1861.87 |

TABLE C-16

## REGIONAL POLLUTION LOADINGS FROM OIL PRODUCTION

IIB IIID
(1979)

| NPC REGION | PRODUCTION (1,000 bbls/ day) | ORGANICS (100 tons/ day) | PARTI-CULATES (tons/day) | NOx (tons/day) | SOx (tons/day) | HYDRO-CARBONS (tons/day) | CARBON MONOXIDE (tons/day) | FIXED LAND (100 acres) |
|---|---|---|---|---|---|---|---|---|
| North Slope | 1420 | 0.041464 | 0 | 0 | 0 | 0 | 0 | 295.36 |
| 1 | 120 | 0.03036 | 0 | 0 | 0 | 0 | 0 | 2.908 |
| 2 | 1080 | 0.031536 | 14.4 | 87.12 | 196.2 | 28.28 | 125.576 | 224.64 |
| 2A | 160 | 0.04048 | 0 | 0 | 0 | 0 | 0 | 3.872 |
| 3 | 180 | 0.005256 | 0 | 0 | 0 | 0 | 0 | 37.44 |
| 4 | 540 | 0.015768 | 0 | 0 | 0 | 0 | 0 | 112.32 |
| 5 | 1690 | 0.049348 | 0 | 0 | 0 | 0 | 0 | 351.52 |
| 6 | 2980 | 0.087016 | 0 | 0 | 0 | 25.4 | 125 | 619.84 |
| 6A | 1390 | 0.35167 | 0 | 0 | 0 | 0 | 0 | 33.638 |
| 7 | 560 | 0.016352 | 0 | 0 | 0 | 0 | 0 | 116.48 |
| 8-9-10 | 210 | 0.006132 | 0 | 0 | 0 | 0 | 0 | 43.68 |
| 11 | 100 | 0.00292 | 0 | 0 | 0 | 0 | 0 | 20.8 |
| 11A | 60 | 0.01518 | 0 | 0 | 0 | 0 | 0 | 1.452 |
| National Totals | 10490 | 0.693482 | 14.4 | 87.12 | 196.2 | 53.68 | 250.576 | 1863.95 |

# TABLE C-17

## REGIONAL POLLUTION LOADINGS FROM OIL PRODUCTION

IIC IIID
(1979)

| EPC REGION | PRODUCTION (1,000 bbls/ day) | ORGANICS (100 tons/ day) | PARTI- CULATES (tons/day) | NOx (tons/day) | SOx (tons/day) | HYDRO- CARBONS (tons/day) | CARBON MONOXIDE (tons/day) | FIXED LAND (100 acres) |
|---|---|---|---|---|---|---|---|---|
| North Slope | 1420 | 0.041464 | 0 | 0 | 0 | 0 | 0 | 295.36 |
| 1 | 120 | 0.03036 | 0 | 0 | 0 | 0 | 0 | 2.904 |
| 2 | 1040 | 0.030368 | 13.6 | 82.28 | 135.3 | 2.72 | 0.544 | 216.32 |
| 2A | 160 | 0.04048 | 0 | 0 | 0 | 0 | 0 | 3.872 |
| 3 | 180 | 0.005256 | 0 | 0 | 0 | 0 | 0 | 37.44 |
| 4 | 540 | 0.015768 | 0 | 0 | 0 | 0 | 0 | 112.32 |
| 5 | 1670 | 0.048764 | 0 | 0 | 0 | 0 | 0 | 347.36 |
| 6 | 2950 | 0.08614 | 0 | 0 | 0 | 12.7 | 62.5 | 613.6 |
| 6A | 1390 | 0.35167 | 0 | 0 | 0 | 0 | 0 | 33.638 |
| 7 | 560 | 0.016352 | 0 | 0 | 0 | 0 | 0 | 116.48 |
| 8-9-10 | 210 | 0.006132 | 0 | 0 | 0 | 0 | 0 | 43.68 |
| 11 | 100 | 0.00292 | 0 | 0 | 0 | 0 | 0 | 20.8 |
| 11A | 60 | 0.01518 | 0 | 0 | 0 | 0 | 0 | 1.452 |
| National Totals | 10400 | 0.690854 | 13.6 | 82.28 | 185.3 | 15.42 | 63.004 | 1845.23 |

# TABLE C-18

## REGIONAL POLLUTION LOADINGS FROM OIL PRODUCTION

## 1985

| NPC REGION | PRODUCTION (1,000 bbls/ day) | ORGANICS (100 tons/ day) | PARTI-CULATES (tons/day) | NOx (tons/day) | SOx (tons/day) | HYDRO-CARBONS (tons/day) | CARBON MONOXIDE (tons/day) | FIXED LAND (100 acres) |
|---|---|---|---|---|---|---|---|---|
| North Slope | 2050 | 0.05986 | 0 | 0 | 0 | 0 | 0 | 426.4 |
| 1 | 330 | 0.08349 | 0 | 0 | 0 | 0 | 0 | 7.936 |
| 2 | 1840 | 0.053728 | 46.4 | 280.72 | 632.2 | 136.28 | 626.856 | [illegible] |
| 2A | 640 | 0.16192 | 0 | 0 | 0 | 0 | 0 | 15.833 |
| 3 | 140 | 0.004688 | 0 | 0 | 0 | 0 | 0 | 29.12 |
| 4 | 550 | 0.01606 | 0 | 0 | 0 | 0 | 0 | 118.4 |
| 5 | 1330 | 0.038836 | 0 | 0 | 0 | 0 | 0 | 276.68 |
| 6 | 2870 | 0.083804 | 0.8 | 4.84 | 10.9 | 89.06 | 437.542 | 506.96 |
| 6A | 1420 | 0.35926 | 0 | 0 | 0 | 0 | 0 | 38.804 |
| 7 | 480 | 0.014016 | 0 | 0 | 0 | 12.7 | 62.5 | 99.58 |
| 8-9-10 | 300 | 0.00876 | 0 | 0 | 0 | 0 | 0 | 62.4 |
| 11 | 120 | 0.003504 | 0 | 0 | 0 | 0 | 0 | 26.96 |
| 11A | 140 | 0.03542 | 0 | 0 | 0 | 0 | 0 | [illegible] |
| National Totals | 12210 | 0.922746 | 47.2 | 285.56 | 643.1 | 238.04 | 1126.89 | 2074.64 |

## TABLE C-19

## NATIONAL POLLUTION LOADINGS FROM OIL PRODUCTION BY RECOVERY METHOD

### 1975

| | PRODUCTION (1,000 bbls/ day) | ORGANICS (100 tons/ day) | PARTI- CULATES (tons/day) | NOx (tons/day) | SOx (tons/day) | HYDRO- CARBONS (tons/day) | CARBON MONOXIDE (tons/day) | FIXED LAND (100 acres) |
|---|---|---|---|---|---|---|---|---|
| OFFSHORE | 1400 | 0.3542 | 0 | 0 | 0 | 0 | 0 | 33.88 |
| ONSHORE | 6715 | 0.196078 | 0 | 0 | 0 | 0 | 0 | 1396.72 |
| STEAM INJECTION | 180 | 0.005256 | 14.4 | 87.12 | 196.2 | 2.88 | 0.576 | 37.44 |
| IN SITU COMBUSTION | 5 | 0.000146 | 0 | 0 | 0 | 6.35 | 31.25 | 1.04 |
| $CO_2$/MISCIBLE | 30 | 0.002336 | 0 | 0 | 0 | 0 | 0 | 16.64 |
| MICELLAR-POLYMER | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| CAUSTIC FLOODING | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| TOTAL | 8380 | 0.558016 | 14.4 | 87.12 | 196.2 | 9.23 | 31.826 | 1485.72 |

# TABLE C-20

## NATIONAL POLLUTION LOADINGS FROM OIL PRODUCTION BY RECOVERY METHOD

### BASE CASE
### (1979)

| | PRODUCTION (1,000 bbls/ day) | ORGANICS (100 tons/ day) | PARTI- CULATES (tons/day) | NOx (tons/day) | SOx (tons/day) | HYDRO- CARBONS (tons/day) | CARBON MONOXIDE (tons/day) | FIXED LAND (100 acres) |
|---|---|---|---|---|---|---|---|---|
| OFFSHORE | 1620 | 0.40986 | 0 | 0 | 0 | 0 | 0 | 39.204 |
| ONSHORE | 7920 | 0.231264 | 0 | 0 | 0 | 0 | 0 | 1647.36 |
| STEAM INJECTION | 170 | 0.004964 | 13.6 | 82.28 | 185.3 | 2.72 | 0.544 | 35.36 |
| IN SITU COMBUSTION | 10 | 0.000292 | 0 | 0 | 0 | 12.7 | 62.5 | 2.08 |
| $CO_2$/MISCIBLE | 30 | 0.000876 | 0 | 0 | 0 | 0 | 0 | 6.24 |
| MICELLAR-POLYMER | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| CAUSTIC FLOODING | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| TOTAL | 9750 | 0.647256 | 13.6 | 82.28 | 185.3 | 15.42 | 63.044 | 1730.24 |

## TABLE C-21

## NATIONAL POLLUTION LOADINGS FROM OIL PRODUCTION BY RECOVERY METHOD

IIA
(1979)

| | PRODUCTION (1,000 bbls/ day) | ORGANICS (100 tons/ day) | PARTI-CULATES (tons/day) | NOx (tons/day) | SOx (tons/day) | HYDRO-CARBONS (tons/day) | CARBON MONOXIDE (tons/day) | FIXED LAND (100 acres) |
|---|---|---|---|---|---|---|---|---|
| OFFSHORE | 1730 | 0.43769 | 0 | 0 | 0 | 0 | 0 | 41.866 |
| ONSHORE | 8430 | 0.246156 | 0 | 0 | 0 | 0 | 0 | 1753.44 |
| STEAM INJECTION | 170 | 0.004964 | 13.6 | 82.28 | 185.3 | 2.72 | 0.544 | 85.36 |
| IN SITU COMBUSTION | 40 | 0.001168 | 0 | 0 | 0 | 50.8 | 250 | 8.32 |
| $CO_2$/MISCIBLE | 90 | 0.002628 | 0 | 0 | 0 | 0 | 0 | 18.72 |
| MICELLAR-POLYMER | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| CAUSTIC FLOODING | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| TOTAL | 10469 | 0.692606 | 13.6 | 82.28 | 185.3 | 53.52 | 250.544 | 1857.71 |

## TABLE C-22

## NATIONAL POLLUTION LOADINGS FROM OIL PRODUCTION BY RECOVERY METHOD

IIB
(1979)

| | PRODUCTION (1,000 bbls/ day) | ORGANICS (100 tons/ day) | PARTI-CULATES (tons/day) | NOx (tons/day) | SOx (tons/day) | HYDRO-CARBONS (tons/day) | CARBON MONOXIDE (tons/day) | FIXED LAND (100 acres) |
|---|---|---|---|---|---|---|---|---|
| OFFSHORE | 1730 | 0.43769 | 0 | 0 | 0 | 0 | 0 | 41.866 |
| ONSHORE | 8430 | 0.246156 | 0 | 0 | 0 | 0 | 0 | 1753.44 |
| STEAM INJECTION | 180 | 0.005256 | 14.4 | 87.12 | 196.2 | 2.88 | 0.576 | 37.44 |
| IN SITU COMBUSTION | 40 | 0.001168 | 0 | 0 | 0 | 50.8 | 250 | 8.32 |
| $CO_2$/MISCIBLE | 90 | 0.002628 | 0 | 0 | 0 | 0 | 0 | 18.72 |
| MICELLAR-POLYMER | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| CAUSTIC FLOODING | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| TOTAL | 10470 | 0.692898 | 14.4 | 87.12 | 196.2 | 53.68 | 250.576 | 1859.79 |

## TABLE C-23

## NATIONAL POLLUTION LOADINGS FROM OIL PRODUCTION BY RECOVERY METHOD

IIC
(1979)

| | PRODUCTION (1,000 bbls/ day) | ORGANICS (100 tons/ day) | PARTI-CULATES (tons/day) | NOx (tons/day) | SOx (tons/day) | HYDRO-CARBONS (tons/day) | CARBON MONOXIDE (tons/day) | FIXED LAND (100 acres) |
|---|---|---|---|---|---|---|---|---|
| OFFSHORE | 1730 | 0.43769 | 0 | 0 | 0 | 0 | 0 | 41.866 |
| ONSHORE | 8440 | 0.246448 | 0 | 0 | 0 | 0 | 0 | 1755.52 |
| STEAM INJECTION | 170 | 0.004964 | 13.6 | 82.28 | 185.3 | 2.72 | 0.544 | 35.36 |
| IN SITU COMBUSTION | 10 | 0.000292 | 0 | 0 | 0 | 12.7 | 62.5 | 2.08 |
| $CO_2$/MISCIBLE | 30 | 0.000876 | 0 | 0 | 0 | 0 | 0 | 6.24 |
| MICELLAR-POLYMER | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| CAUSTIC FLOODING | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| TOTAL | 10380 | 0.69027 | 13.6 | 82.28 | 185.3 | 15.42 | 63.044 | 1841.07 |

## TABLE C-24

## NATIONAL POLLUTION LOADINGS FROM OIL PRODUCTION BY RECOVERY METHOD

IIA IIIA
(1979)

|  | PRODUCTION (1,000 bbls/ day) | ORGANICS (100 tons/ day) | PARTI-CULATES (tons/day) | NOx (tons/day) | SOx (tons/day) | HYDRO-CARBONS (tons/day) | CARBON MONOXIDE (tons/day) | FIXED LAND (100 acres) |
|---|---|---|---|---|---|---|---|---|
| OFFSHORE | 1720 | 0.43516 | 0 | 0 | 0 | 0 | 0 | 41.624 |
| ONSHORE | 8350 | 0.24382 | 0 | 0 | 0 | 0 | 0 | 1736.8 |
| STEAM INJECTION | 210 | 0.006132 | 16.8 | 101.64 | 228.9 | 3.36 | 0.672 | 43.68 |
| IN SITU COMBUSTION | 60 | 0.001752 | 0 | 0 | 0 | 76.2 | 375 | 12.48 |
| $CO_2$/MISCIBLE | 190 | 0.005548 | 0 | 0 | 0 | 0 | 0 | 39.52 |
| MICELLAR-POLYMER | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| CAUSTIC FLOODING | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| TOTAL | 10530 | 0.692412 | 16.8 | 101.64 | 228.9 | 79.56 | 375.672 | 1874.1 |

## TABLE C-25

## NATIONAL POLLUTION LOADINGS FROM OIL PRODUCTION BY RECOVERY METHOD

IIB IIIA
(1979)

| | PRODUCTION (1,000 bbls/ day) | ORGANICS (100 tons/ day) | PARTI- CULATES (tons/day) | NOx (tons/day) | SOx (tons/day) | HYDRO- CARBONS (tons/day) | CARBON MONOXIDE (tons/day) | FIXED LAND (100 acres) |
|---|---|---|---|---|---|---|---|---|
| OFFSHORE | 1720 | 0.43516 | 0 | 0 | 0 | 0 | 0 | 41.624 |
| ONSHORE | 8290 | 0.242068 | 0 | 0 | 0 | 0 | 0 | 1724.32 |
| STEAM INJECTION | 210 | 0.006132 | 16.8 | 101.64 | 220.9 | 3.36 | 0.672 | 43.68 |
| IN SITU COMBUSTION | 60 | 0.001752 | 0 | 0 | 0 | 76.2 | 375 | 12.48 |
| $CO_2$/MISCIBLE | 190 | 0.005548 | 0 | 0 | 0 | 0 | 0 | 39.52 |
| MICELLAR-POLYMER | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| CAUSTIC FLOODING | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| TOTAL | 10470 | 0.69066 | 16.8 | 101.64 | 220.9 | 79.56 | 375.672 | 1861.62 |

## TABLE C-26

## NATIONAL POLLUTION LOADINGS FROM OIL PRODUCTION BY RECOVERY METHOD

IIC IIIA
(1979)

| | PRODUCTION (1,000 bbls/ day) | ORGANICS (100 tons/ day) | PARTI-CULATES (tons/day) | NOx (tons/day) | SOx (tons/day) | HYDRO-CARBONS (tons/day) | CARBON MONOXIDE (tons/day) | FIXED LAND (100 acres) |
|---|---|---|---|---|---|---|---|---|
| OFFSHORE | 1730 | 0.43769 | 0 | 0 | 0 | 0 | 0 | 41.866 |
| ONSHORE | 8440 | 0.246448 | 0 | 0 | 0 | 0 | 0 | 1755.52 |
| STEAM INJECTION | 210 | 0.006132 | 16.8 | 101.64 | 228.9 | 3.36 | 0.672 | 43.68 |
| IN SITU COMBUSTION | 60 | 0.001752 | 0 | 0 | 0 | 76.2 | 375 | 12.48 |
| $CO_2$/MISCIBLE | 190 | 0.005548 | 0 | 0 | 0 | 0 | 0 | 39.52 |
| MICELLAR-POLYMER | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| CAUSTIC FLOODING | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| TOTAL | 10630 | 0.69757 | 16.8 | 101.64 | 226.9 | 79.56 | 375.672 | 1893.07 |

# TABLE C-27

## NATIONAL POLLUTION LOADINGS FROM OIL PRODUCTION BY RECOVERY METHOD

IIA IIIB
(1979)

| | PRODUCTION (1,000 bbls/ day) | ORGANICS (100 tons/ day) | PARTI- CULATES (tons/day) | NOx (tons/day) | SOx (tons/day) | HYDRO- CARBONS (tons/day) | CARBON MONOXIDE (tons/day) | FIXED LAND (100 acres) |
|---|---|---|---|---|---|---|---|---|
| OFFSHORE | 1710 | 0.43263 | 0 | 0 | 0 | 0 | 0 | 41.302 |
| ONSHORE | 8240 | 0.249608 | 0 | 0 | 0 | 0 | 0 | 1713.92 |
| STEAM INJECTION | 210 | 0.006132 | 16.8 | 101.64 | 220.9 | 3.36 | 0.672 | 43.68 |
| IN SITU COMBUSTION | 60 | 0.001752 | 0 | 0 | 0 | 76.2 | 375 | 12.48 |
| $CO_2$/MISCIBLE | 250 | 0.0073 | 0 | 0 | 0 | 0 | 0 | 52. |
| MICELLAR POLYMER | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| CAUSTIC FLOODING | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| TOTAL | 10470 | 0.688422 | 16.8 | 101.64 | 220.9 | 79.56 | 375.672 | 1863.46 |

## TABLE C-28

## NATIONAL POLLUTION LOADINGS FROM OIL PRODUCTION BY RECOVERY METHOD

IIB IIIB
(1979)

| | PRODUCTION (1,000 bbls/ day) | ORGANICS (100 tons/ day) | PARTI- CULATES (tons/day) | NOx (tons/day) | SOx (tons/day) | HYDRO- CARBONS (tons/day) | CARBON MONOXIDE (tons/day) | FIXED LAND (100 acres) |
|---|---|---|---|---|---|---|---|---|
| OFFSHORE | 1700 | 0.4301 | 0 | 0 | 0 | 0 | 0 | 41.14 |
| ONSHORE | 8180 | 0.238856 | 0 | 0 | 0 | 0 | 0 | 1701.44 |
| STEAM INJECTION | 210 | 0.006132 | 16.8 | 101.64 | 228.9 | 3.36 | 0.672 | 43.68 |
| IN SITU COMBUSTION | 60 | 0.001752 | 0 | 0 | 0 | 76.2 | 375 | 12.48 |
| $CO_2$/MISCIBLE | 250 | 0.0073 | 0 | 0 | 0 | 0 | 0 | 52. |
| MICELLAR-POLYMER | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| CAUSTIC FLOODING | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| TOTAL | 10400 | 0.68414 | 16.8 | 101.64 | 228.9 | 79.56 | 375.672 | 1850.74 |

# TABLE C-29

## NATIONAL POLLUTION LOADINGS FROM OIL PRODUCTION BY RECOVERY METHOD

IIC IIIB
(1979)

| | PRODUCTION (1,000 bbls/ day) | ORGANICS (100 tons/ day) | PARTI-CULATES (tons/day) | NOx (tons/day) | SOx (tons/day) | HYDRO-CARBONS (tons/day) | CARBON MONOXIDE (tons/day) | FIXED LAND (100 acres) |
|---|---|---|---|---|---|---|---|---|
| OFFSHORE | 1720 | 0.43516 | 0 | 0 | 0 | 0 | 0 | 41.624 |
| ONSHORE | 8340 | 0.243528 | 0 | 0 | 0 | 0 | 0 | 1734.72 |
| STEAM INJECTION | 210 | 0.006132 | 16.8 | 101.64 | 220.9 | 3.36 | 0.672 | 43.68 |
| IN SITU COMBUSTION | 60 | 0.001752 | 0 | 0 | 0 | 76.2 | 375 | 12.48 |
| $CO_2$/MISCIBLE | 250 | 0.0073 | 0 | 0 | 0 | 0 | 0 | 52. |
| MICELLAR-POLYMER | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| CAUSTIC FLOODING | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| TOTAL | 10580 | 0.693872 | 16.8 | 101.64 | 220.9 | 79.56 | 375.672 | 1884.5 |

# TABLE C-30

## NATIONAL POLLUTION LOADINGS FROM OIL PRODUCTION BY RECOVERY METHOD

IIA IIIC
(1979)

| | PRODUCTION (1,000 bbls/day) | ORGANICS (100 tons/day) | PARTICULATES (tons/day) | NOx (tons/day) | SOx (tons/day) | HYDROCARBONS (tons/day) | CARBON MONOXIDE (tons/day) | FIXED LAND (100 acres) |
|---|---|---|---|---|---|---|---|---|
| OFFSHORE | 1760 | 0.44528 | 0 | 0 | 0 | 0 | 0 | 42.592 |
| ONSHORE | 8430 | 0.246156 | 0 | 0 | 0 | 0 | 0 | 1753.44 |
| STEAM INJECTION | 170 | 0.004964 | 13.6 | 82.28 | 185.3 | 2.72 | 0.544 | 35.36 |
| IN SITU COMBUSTION | 40 | 0.001168 | 0 | 0 | 0 | 50.8 | 250 | 8.32 |
| $CO_2$/MISCIBLE | 90 | 0.002628 | 0 | 0 | 0 | 0 | 0 | 18.72 |
| MICELLAR-POLYMER | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| CAUSTIC FLOODING | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| TOTAL | 10490 | 0.700196 | 13.6 | 82.28 | 185.3 | 53.52 | 250.544 | 1858.43 |

TABLE C-31

## NATIONAL POLLUTION LOADINGS FROM OIL PRODUCTION BY RECOVERY METHOD

IIB IIIC
(1979)

|  | PRODUCTION (1,000 bbls/day) | ORGANICS (100 tons/day) | PARTI-CULATES (tons/day) | NOx (tons/day) | SOx (tons/day) | HYDRO-CARBONS (tons/day) | CARBON MONOXIDE (tons/day) | FIXED LAND (100 acres) |
|---|---|---|---|---|---|---|---|---|
| OFFSHORE | 1760 | 0.44528 | 0 | 0 | 0 | 0 | 0 | 12.592 |
| ONSHORE | 8430 | 0.246156 | 0 | 0 | 0 | 0 | 0 | 1723.44 |
| STEAM INJECTION | 180 | 0.005256 | 14.4 | 37.12 | 196.2 | 2.88 | 0.576 | 37.44 |
| IN SITU COMBUSTION | 40 | 0.001168 | 0 | 0 | 0 | 50.8 | 250 | 8.32 |
| $CO_2$/MISCIBLE | 90 | 0.002628 | 0 | 0 | 0 | 0 | 0 | 18.72 |
| MICELLAR POLYMER | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| CAUSTIC FLOODING | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| TOTAL | 10500 | 0.700488 | 14.4 | 37.12 | 196.2 | 53.68 | 250.576 | 1800.51 |

# TABLE C-32

## NATIONAL POLLUTION LOADINGS FROM OIL PRODUCTION BY RECOVERY METHOD

## IIC IIIC
## (1979)

| | PRODUCTION (1,000 bbls/ day) | ORGANICS (100 tons/ day) | PARTI-CULATES (tons/day) | NOx (tons/day) | SOx (tons/day) | HYDRO-CARBONS (tons/day) | CARBON MONOXIDE (tons/day) | FIXED LAND (100 acres) |
|---|---|---|---|---|---|---|---|---|
| OFFSHORE | 1760 | 0.44523 | 0 | 0 | 0 | 0 | 0 | 42.592 |
| ONSHORE | 8440 | 0.246448 | 0 | 0 | 0 | 0 | 0 | 1755.52 |
| STEAM INJECTION | 170 | 0.004964 | 13.6 | 82.28 | 185.3 | 2.72 | 0.544 | 35.36 |
| IN SITU COMBUSTION | 10 | 0.000292 | 0 | 0 | 0 | 12.7 | 62.5 | 2.08 |
| $CO_2$/MISCIBLE | 30 | 0.000876 | 0 | 0 | 0 | 0 | 0 | 6.24 |
| MICELLAR-POLYMER | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| CAUSTIC FLOODING | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| TOTAL | 10410 | 0.69786 | 13.6 | 82.28 | 185.3 | 15.42 | 63.044 | 1841.76 |

## TABLE C-33

## NATIONAL POLLUTION LOADINGS FROM OIL PRODUCTION BY RECOVERY METHOD

IIA IIID
(1979)

| | PRODUCTION (1,000 bbls/day) | ORGANICS (100 tons/day) | PARTICULATES (tons/day) | NOx (tons/day) | SOx (tons/day) | HYDROCARBONS (tons/day) | CARBON MONOXIDE (tons/day) | FIXED LAND (100 acres) |
|---|---|---|---|---|---|---|---|---|
| OFFSHORE | 1730 | 0.43769 | 0 | 0 | 0 | 0 | 0 | 41.866 |
| ONSHORE | 8450 | 0.24674 | 0 | 0 | 0 | 0 | 0 | 1757.6 |
| STEAM INJECTION | 170 | 0.004964 | 13.6 | 82.28 | 185.3 | 2.72 | 0.544 | 35.36 |
| IN SITU COMBUSTION | 40 | 0.001168 | 0 | 0 | 0 | 50.8 | 250 | 8.32 |
| $CO_2$/MISCIBLE | 90 | 0.002628 | 0 | 0 | 0 | 0 | 0 | 18.72 |
| MICELLAR-POLYMER | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| CAUSTIC FLOODING | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| TOTAL | 10480 | 0.69319 | 13.6 | 82.28 | 185.3 | 53.52 | 250.544 | 1861.87 |

## TABLE C-34

## NATIONAL POLLUTION LOADINGS FROM OIL PRODUCTION BY RECOVERY METHOD

### IIB IIID
### (1979)

| | PRODUCTION (1,000 bbls/ day) | ORGANICS (100 tons/ day) | PARTI-CULATES (tons/day) | NOx (tons/day) | SOx (tons/day) | HYDRO-CARBONS (tons/day) | CARBON MONOXIDE (tons/day) | FIXED LAND (100 acres) |
|---|---|---|---|---|---|---|---|---|
| OFFSHORE | 1730 | 0.43769 | 0 | 0 | 0 | 0 | 0 | 41.866 |
| ONSHORE | 8450 | 0.24674 | 0 | 0 | 0 | 0 | 0 | 1757.6 |
| STEAM INJECTION | 180 | 0.005256 | 14.4 | 87.12 | 196.2 | 2.88 | 0.576 | 37.44 |
| IN SITU COMBUSTION | 40 | 0.001168 | 0 | 0 | 0 | 50.8 | 250 | 8.32 |
| $CO_2$/MISCIBLE | 90 | 0.002628 | 0 | 0 | 0 | 0 | 0 | 18.72 |
| MICELLAR-POLYMER | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| CAUSTIC FLOODING | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| TOTAL | 10490 | 0.693482 | 14.4 | 87.12 | 196.2 | 53.68 | 250.576 | 1863.95 |

## TABLE C-35

## NATIONAL POLLUTION LOADINGS FROM OIL PRODUCTION BY RECOVERY METHOD

IIC IIID
(1979)

| | PRODUCTION (1,000 bbls/ day) | ORGANICS (100 tons/ day) | PARTI- CULATES (tons/day) | NOx (tons/day) | SOx (tons/day) | HYDRO- CARBONS (tons/day) | CARBON MONOXIDE (tons/day) | FIXED LAND (100 acres) |
|---|---|---|---|---|---|---|---|---|
| OFFSHORE | 1730 | 0.43769 | 0 | 0 | 0 | 0 | 0 | 41.866 |
| ONSHORE | 8460 | 0.247032 | 0 | 0 | 0 | 0 | 0 | 1759.68 |
| STEAM INJECTION | 170 | 0.004964 | 13.6 | 82.28 | 185.3 | 2.72 | 0.544 | 35.36 |
| IN SITU COMBUSTION | 10 | 0.000292 | 0 | 0 | 0 | 12.7 | 62.5 | 2.08 |
| $CO_2$/MISCIBLE | 30 | 0.000876 | 0 | 0 | 0 | 0 | 0 | 6.24 |
| MICELLAR-POLYMER | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| CAUSTIC FLOODING | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| TOTAL | 10400 | 0.690854 | 13.6 | 82.28 | 185.3 | 15.42 | 63.044 | 1845.23 |

# TABLE C-36

## NATIONAL POLLUTION LOADINGS FROM OIL PRODUCTION BY RECOVERY METHOD

### 1985

C-33

| | PRODUCTION (1,000 bbls/ day) | ORGANICS (100 tons/ day) | PARTI-CULATES (tons/day) | NOx (tons/day) | SOx (tons/day) | HYDRO-CARBONS (tons/day) | CARBON MONOXIDE (tons/day) | FIXED LAND (100 acres) |
|---|---|---|---|---|---|---|---|---|
| OFFSHORE | 2530 | 0.64009 | 0 | 0 | 0 | 0 | 0 | 61.256 |
| ONSHORE | 8540 | 0.240076 | 0 | 0 | 0 | 0 | 0 | 1774.28 |
| STEAM INJECTION | 590 | 0.017228 | 47.2 | 285.56 | 643.1 | 9.44 | 1.888 | [illegible] |
| IN SITU COMBUSTION | 180 | 0.005256 | 0 | 0 | 0 | 228.6 | 1125 | 37.49 |
| $CO_2$/MISCIBLE | 290 | 0.008468 | 0 | 0 | 0 | 0 | 0 | [illegible] |
| MICELLAR-POLYMER | 90 | 0.002628 | 0 | 0 | 0 | 0 | 0 | [illegible] |
| CAUSTIC FLOODING | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| TOTAL | 12219 | 0.913746 | 47.2 | 285.56 | 643.1 | 238.04 | 1126.89 | [illegible] |

C-38

# APPENDIX D

## IMPACTS OF OIL SPILLS

# APPENDIX D

## IMPACTS OF OIL SPILLS

### 1. Characteristics of Crude Oil

Crude oil is a mixture of hundreds of organic compounds -- most of them hydrocarbons -- formed over millions of years out of organic matter. The exact composition of crude oil varies, not only from well to well but also within wells, depending on the strata from which oil is being produced in the reservoir. Environmental impacts of spilled oil vary to some extent with the nature of the crude: the composition of an oil slick determines its thickness and rate of spreading, its tendency to form emulsions, the significance of soluble fractions, the attenuation of light and oxygen, and the effectiveness of various cleanup techniques. Nevertheless, most crude oils have many constituents in common, and some of these common constituents, if released into the environment, can be precursors of important impacts.

Crude oil is composed primarily of hydrocarbons with generally less than one-quarter of the total weight being comprised of organic compounds containing such elements as sulfur, nitrogen, and oxygen. Because hydrocarbons are so predominant, crude oils are often characterized by the mix of different hydrocarbon families found in them. One useful classification scheme for crude oil hydrocarbons, based on molecular structure, is the following:[1]

1. Paraffins (normal and branched)
2. Cycloparaffins or naphthenes
3. Aromatics
4. Naphthenic aromatic

These classes are discussed briefly below; the structures of several examples from different hydrocarbon families are illustrated in Figure D-1.

Paraffins (also known as alkanes) are just saturated carbon chains.[2] They may be of the straight-chained (or aliphatic) series whose general formula is $C_nH_{2n+2}$, in which case they are called normal paraffins, or they may have one or more branches. Paraffins usually comprise up to 25 percent of crude oil, tending to predominate in the low boiling point (40° to 230° C) fractions. In general, the boiling point of paraffins and solubility decreases with increasing molecular

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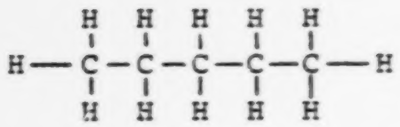
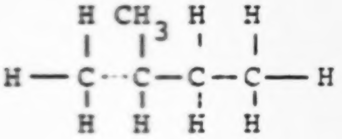
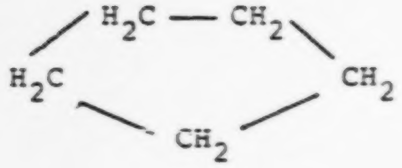


PENTANE (a normal paraffin)

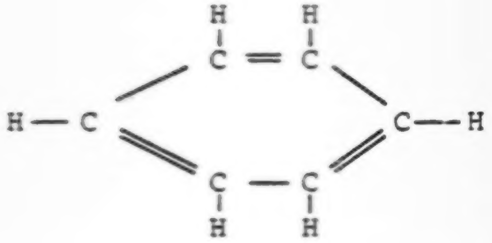
ISOPENTANE
(a branched paraffin)

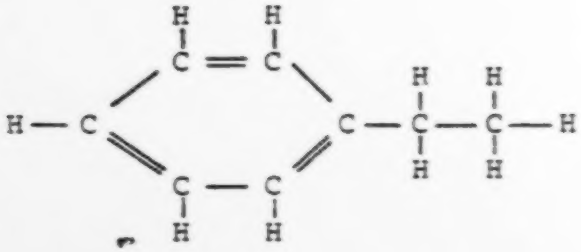




CYCLOPENTANE (a cycloparaffin)

BENZENE
(an aromatic)





ETHYLBENZENE
(an alkyl aromatic)

Figure D-1. Examples from chemical families commonly found in crude oil.

weight. Low-boiling paraffins can cause anesthesia and narcosis in low concentrations; higher concentrations may lead to cell damage or death in many lower invertebrates. High-boiling paraffins are not generally as toxic, although they may interfere with chemical and metabolic processes.[3]

Cycloparaffins (commonly called naphthenes by petroleum engineers) are paraffins which are composed of simple (saturated) carbon rings, such as the cyclopentane molecule drawn in Figure D-1. Single-ringed cycloparaffins are most prevalent in crude oil, but two- to six-ringed cycloparaffins are not uncommon, and ten-ringed compounds are sometimes present. Cycloparaffins normally constitute between 30 and 60 percent of crude oil, and, unlike open paraffins, their abundance is not highly dependent on boiling point. The chemical properties of cycloparaffins are very similar to those of other paraffins.

Aromatics are unsaturated hydrocarbon rings, most of which are based on derivatives or multiples of the six-carbon compound benzene. They comprise around 5 percent of crude oil, with single-ringed compounds being most prevalent. Alkyl benzenes (benzene with one or more saturated straight-chained substitutes, such as ethylbenzene) constitute a major portion of the low-boiling aromatic fraction; dicyclic aromatics (those based on naphthalene) are less common. Polycyclic aromatics occupy the higher-boiling fractions; they rarely constitute as much as 1 percent of crude oil. Aromatics in crude oil have some chemical properties which make them especially worrisome as environmental threats. Single-ringed aromatics are much more soluble (up to 1,780 ppm) than paraffins of similar molecular weight; as a result, they can affect a greater portion of the water column in aquatic or marine environments. They are also among the most toxic of compounds commonly found in crude oil.[4] The higher-boiling, polycyclic aromatics are considerably less soluble (up to 12.5 ppm) than benzene derivatives. Although the long-term effects of most of them are unclear, some polycylics are known carcinogens.

The naphthenic aromatics form a large and highly varied class of compounds containing both saturated (cycloparaffin) and unsaturated (benzene) rings. Most of these compounds are present in crude oil in substituted form: the substituents on the benzene ends are usually short alkyl chains. As a family, this group of compounds normally constitutes between 5 and 30 percent of crude oil. Although the naphtheno-aromatics form a family too diverse to be characterized by many properties, they tend to be large compounds (as many as 300 carbons) with relatively low solubilities.

Crude oil constituents which do not fit into any of these four categories form a residual fraction which comprises from 0 to 20 percent of most crudes. They include high-boiling hydrocarbons of many varieties, some with molecular weights as high as 3,000, along with some organics containing oxygen, sulfur, nitrogen, and trace metals. Many of the larger compounds are really complexes of condensed aromatics and cycloparaffins connected into layers by a lattice of aliphatic paraffins.[5]

Some important properties of major crude oil hydrocarbons are summarized in Table D-1. Many petroleum engineers prefer to classify crude oil constituents by fractions based on boiling point ranges. Table D-2 gives a fairly standard classification scheme based on boiling point fractions.

## 2. Extent, Location and Frequency of Marine Oil Spillage

Oil can enter the marine environment in a variety of ways. Of interest in evaluating the environmental impact of the proposed pricing policies are those directly pertaining to oil production and associated marine transportation. The most significant of these include:

- Chronic, deliberate discharges by tankers and barges;
- Spillage during terminal transfers;
- Tanker accidents -- collisions and rammings;
- Offshore oil platform accidents -- blowouts, fires and explosions; and
- Pipeline leakages.

Worldwide, the total marine pollution is variously estimated at between 1 and 5 million metric tons annually (mta). The variance can largely be attributed to an unresolved debate over the amount of land-released oils which eventually return to the sea. In the five categories listed above the total pollution is estimated at between 1.10 and 1.75 million mta. Of this, approximately 1 million mta comes from the first source, "chronic, deliberate discharges by tankers and barges," which are a result of tank cleaning operations. The next largest categories are tanker accidents and offshore operations with estimated pollution on the order of 100,000 to 200,000 mta.[6,7,8]

# TABLE D-1

## CHARACTERISTICS OF HYDROCARBONS IN CRUDE OIL

| COMPOUNDS | CARBON NUMBER | BOILING POINT (°C) | MELTING POINT (°C) | DENSITY (SG) | SOLUBILITY IN WATER | PRESENCE IN OKLAHOMA CRUDE (% vol) |
|---|---|---|---|---|---|---|
| PARAFFINS | | | | | | |
| Methane | 1 | -161.5 | | 0.424 | 90 ml/l(20°C) | |
| Ethane | 2 | - 88.5 | | 0.546 | 47 ml/l(20°C) | |
| Propane | 3 | - 42.2 | | 0.542 | 65 ml/l(18°C) | |
| Butane | 4 | - 0.5 | | 0.579 | 150 ml/l(17°C) | |
| Pentane | 5 | 36.2 | | 0.626 | 360 ppm(17°C) | |
| Hexane | 6 | 69.0 | | 0.660 | 138 ppm(15.5°C) | 1.8 |
| Heptane | 7 | 98.5 | | 0.684 | 52 ppm(15.5°C) | 2.3 |
| Octane | 8 | 125.7 | | 0.703 | 15 ppm(15.5°C) | 1.9 |
| Nonane | 9 | 150.8 | | 0.718 | c. 10 ppm. | 1.8 |
| Decane | 10 | 174.1 | | 0.730 | c. 3 ppm. | 1.8 |
| Undecane | 11 | 195.9 | | 0.741 | | 1.7 |
| Dodecane | 12 | 216.3 | | 0.766 | | 1.7 |
| Tridecane | 13 | 235.6 | - 5.5 | 0.756 | | 1.6 |
| Tetradecane | 14 | 253.6 | 6 | 0.763 | | 1.4 |
| Pentadecane | 15 | 270.7 | 10 | 0.769 | | 1.2 |
| Hexadecane (Catane) | 16 | 287.1 | 18 | 0.773 | | 1.0 |
| Heptadecane | 17 | 302.6 | 22 | 0.778 | | 0.9 |
| NAPHTHENES | | | | | | |
| Cyclopropane | 3 | - 33 | | | "slight" | |
| Cyclobutane | 4 | 13 | | | | |
| Cyclopentane | 5 | 49.3 | | 0.751 | | 0.05 |
| Methylcyclopentane | 6 | 71.8 | | 0.749 | | 0.9 |
| Cyclohexane | 6 | 80.7 | | 0.779 | | 0.7 |
| Methylcyclohexane | 7 | 100.9 | | 0.769 | | 1.6 |
| Ethylcyclopentane | 7 | 103.5 | | 0.763 | | 0.2 |
| Ethylcyclohexane | 8 | 131.8 | | 0.788 | | 0.4 |
| Trimethylcyclohexane | 9 | 141.2 | | 0.777 | | 0.2 |
| AROMATICS | | | | | | |
| Benzene | 6 | 80.1 | | 0.879 | 820 ppm(22°C) | 0.2 |
| Toluene | 7 | 110.6 | | 0.866 | 470 ppm(15°C) | 0.5 |
| Ethylbenzene | 8 | 136.2 | | 0.867 | 140 ppm(15°C) | 0.2 |
| p-Xylene | 8 | 138.4 | | 0.861 | | 0.1 |
| m-Xylene | 8 | 139.1 | | 0.864 | c. 30 ppm | 0.5 |
| O-Xylene | 8 | 144.4 | | 0.874 | | 0.3 |
| iso-Propylbenzene (Cumene) | 9 | 152.4 | | 0.864 | | 0.07 |
| n-Propylbenzene | 9 | 159.2 | | 0.862 | 60 ppm(15°C) | 0.09 |
| Naphthalene | 10 | 217.9 | 80.2 | 1.145 | c. 20 ppm | 0.06 |
| 2-Methylnaphthalene | 11 | 241.1 | 37 | 1.029 | | 0.2 |
| 1-Methylnaphthalene | 11 | 244.8 | - 22 | 1.029 | | 0.1 |
| Dimethylnaphthalene | 12 | 262.0 | - 18 | 1.016 | | |
| Trimethylnaphthalene | 13 | 285.0 | 92 | 1.01 | | |
| Anthracene | 14 | 354 | 216 | 1.25 | | |

Source: Nelson-Smith, 1973, p. 72.

## TABLE D-2

## CLASSIFICATION OF CRUDE OIL FRACTIONS BY BOILING POINT RANGES

| FRACTION | DESCRIPTION | % BY WT. IN CRUDE OIL | DENSITY (GM/ML) | BOILING POINT (°C) | MOLECULAR WEIGHT | VAPOR PRESS. @ 20°C. (mm) | SOLUBILITY (gm/$10^6$ gm DISTILLED $H_2O$ |
|---|---|---|---|---|---|---|---|
| 1 | Paraffin $C_6$-$C_{12}$ | .1-20 | .66-.77 | 69-230 | 86-170 | 110-.1 | 9.5-.01 |
| 2 | Paraffin $C_{13}$-$C_{25}$ | $0^+$-10 | .77-.78 | 230-405 | 184-352 | .1 | .01-.004 |
| 3 | Cycloparaffin $C_6$-$C_{12}$ | 5-30 | .75-.9 | 70-230 | 84-164 | 100-1. | 55-1. |
| 4 | Cycloparaffin $C_{13}$-$C_{23}$ | 5-30 | .9-1. | 230-405 | 156-318 | 1.-0 | 1.-0 |
| 5 | Aromatic (Mono- and di-Cyclic) $C_6$-$C_{11}$ | 0-5 | .88-1.1 | 80-240 | 78-143 | 72-.1 | 1780.-0. |
| 6 | Aromatic (Poly-Cyclic) $C_{12}$-$C_{18}$ | $0^+$-5 | 1.1-1.2 | 240-400 | 128-234 | .1-0 | 12.5-0 |
| 7 | Naphtheno-Aromatic $C_9$-$C_{25}$ | 5-30 | .97-1.2 | 180-400 | 116-300 | 1.-0 | 1.-0 |
| 8 | Residual (including heterocycles) | 10-70 | 1.-1.1 | >400 | 300-900 | 0 | 0 |

(Source: Moore, et al., 1973)

To compare this with concurrent total production data we quote the 1971 world figures. In 1971 the total world production was approximately 2,400 million metric tons. About 1,355 million metric tons of oil were transported by sea, of which 1,100 million tons were crude oil.[9]

The MIT Offshore Oil Task Group has prepared a regional analysis of U.S. oil spillage in 1971.[10] These data, presented in Table D-3, do not include figures for intentional discharge such as those created by tanker cleaning processes. They do, however, provide an instructive comparison of the relative magnitudes of specific oil pollution problems in the four regions. For example, it is clear that New England accounts for a disproportionately large fraction of total spillage. However, nearly half of this amount is accounted for by one spill in New Haven Harbor. Excluding this large anomaly, the next largest component of the total figure is spillage in the Gulf Coast region from pipelines less than 3 miles offshore. The nearshore pipes are much older than the outer network and this partially explains the higher leakage rage. The terminal area tanker spills in New England and three nearshore pipeline leaks in the Gulf comprise over half of the accidental spillage recorded for that year. Other significant contributors were bulk storage and transfer in the Mid-Atlantic Region and terminal area tanker spills, refinery area spills, and offshore platform spills in the Gulf.

By comparing the Coast Guard statistics with world data, the MIT group has developed some ranges of expected spillage rates (Table D-4). Once again, these do not include discharge. According to oil spill statistics between 1964 and 1971, the actual spillage rate for imported oil was .0035 percent, which lies slightly above the top of the range given.[11] Current spillage of all oil should be somewhat less than this, and hence lie within the specified range, for two reasons. First, the imported oil figure excludes domestic transportation which is handled by U.S. crews. U.S. crews have been noted to have a somewhat better safety performance than average. Second, improving technology over the past 10 years has served to decrease the likelihood of spills, so a figure based on the period 1964-1971 would be higher than what should be anticipated today. By using the insights gained from the regional study, (Table D-3) to pick a value from within these ranges (Table D-4), a "best estimate" may be developed for use in particular scenarios. Thus the range of .0001 to .009 percent spillage rate for pipelines may be refined by considering the state of the pipeline in question. If there will be extensive use of old lines within the 3-mile limit then a high value should be assigned. If there will be new construction of modern lines, a low value would be chosen.

## TABLE D-3

## VOLUME OF U.S. OIL SPILLAGE BY REGION IN 1971

(Barrels)

| | TOTAL | TANKERS<br>TERMINAL | <br>OFFSHORE | BULK STORAGE & TRANSFER | REFINERIES | OFFSHORE PIPELINES<br>> 3MI | <br>< 3MI | OFFSHORE OIL RIGS |
|---|---|---|---|---|---|---|---|---|
| New England | 18,927 | 18,002 | 0 | 925 | 0 | 0 | 0 | 0 |
| Mid-Atlantic | 6,224 | 1,212 | 0 | 5,000 | 12 | 0 | 0 | 0 |
| Gulf Coast | 27,085 | 6,593 | 266 | 151 | 4,773 | 347 | 12,255 | 2,700 |
| Southern California | 734 | 691 | 2 | 20 | 21 | 0 | 0 | 0 |
| | 52,970 | 26,498 | 268 | 6,096 | 4,806 | 347 | 12,255 | 2,700 |

Source: MIT, Offshore Oil Task Group.

## TABLE D-4

## SPILLAGE RATES BY SOURCE
(Percent)

| SPILL SOURCE | SPILLAGE RATE-% OF THROUGHPUT (Low) | (High) |
|---|---|---|
| Tankers & tank barges | .0025 | .003 |
| Transfer & storage facilities | .0001 | .001 |
| Offshore towers | .0007 | .0055 |
| Offshore pipelines | .0001 | .009 |
| Refineries | .0003 | .003 |

Source: MIT, Offshore Oil Task Group.

Similarly, it may be that higher spillage rates at New England terminals should be assigned than at other locations.

Unfortunately, the extremely high variance of spill sizes tends to diminish the value of an estimated spillage rate. In many instances the occurrence of a limited number of catastrophic events can completely alter the year's total. For example, the Torrey Canyon spill of 1967 involved twice as much crude oil as was spilled in the United States in all of 1970. In 1970, three spills accounted for two-thirds of all the oil spilled in the navigable waters of the United States. Another accident in 1967, involving the breaking of a pipeline in the Gulf of Mexico by a dragging anchor, resulted in the spill of 160,639 barrels of oil; the total spillage in the Gulf in 1967 resulting from all blowouts, platform fires and explosions, and pipeline breaks (including the above spill) was only 160,799 barrels. Because of this one incident, regulations were imposed requiring the burial of pipelines laid in water less than 200 meters deep, with the result that no repetition of this sort of disastrous spill has occurred.

Table D-5 presents some recent spillage figures developed from Coast Guard data for the years 1970-1974. Besides displaying the notable variance of total annual spillage from year to year it documents the fact that coastal waters are the prime location for marine spills. One reason why spills are of importance even though discharges involve much greater volumes is that spills tend to occur in coastal regions while disposal of ballast generally does not take place in the vicinity of U.S. waters.[12] (Note that the apparent discrepancy between the 1971 figures on total volume of spills quoted in Tables D-3 and D-6 is due to the fact that the totals in Table D-3 are only for the four regions discussed and do not represent national totals.) Even so, the numerical dominance of discharges makes them important and the associated spillage rates need to be determined. The first important consideration is that the 20 percent of all tankers that do not use the "Load on Top" (LOT, a method of reducing intentional discharges) account for approximately 75 percent of the discharge pollution.[13] For those ships which do not use LOT, the discharge rate is about 0.35 percent, a figure which is based upon the estimated amount of oil left clinging to the sides of the tanks after the tanks are emptied at terminals. This figure is somewhat controversial, and estimates of non-LOT discharge are as low as 0.1 percent and as high as 0.9 percent. The LOT tankers have a rate of about .03 percent. Unfortunately, the LOT method can only be used for tankers engaging in crude oil transport over fairly long distances. This is due to the necessity of a few days 'settling' time for the process to be effective.

## TABLE D-5

## SELECTED LOCATIONS OF REPORTED OIL SPILLS
(1970 through 1974)

| LOCATION[a] | NUMBER OF SPILLS | PERCENTAGE OF TOTAL SPILLS | SPILL VOLUME (Barrels) | PERCENTAGE OF TOTAL SPILL VOLUME |
|---|---|---|---|---|
| Coastal waters[b] | | | | |
| 1974 | 9,503 | 68.0 | 185,709 | 46.1 |
| 1973 | 9,871 | 74.1 | 368,820 | 63.7 |
| 1972 | 7,442 | 74.9 | 339,944 | 75.9 |
| 1971 | 7,516 | 86.1 | 160,905 | 76.4 |
| 1970 | 2,786 | 75.1 | 227,544 | 62.7 |
| Contiguous zone[c] | | | | |
| 1974 | 164 | 1.2 | 24,706 | 0.6 |
| 1973 | 483 | 3.6 | 29,020 | 5.0 |
| 1972 | 801 | 8.1 | 828 | 0.2 |
| 1971 | 396 | 4.5 | 15,504 | 7.4 |
| 1970 | 349 | 9.4 | 74,796 | 20.6 |
| Total spill volume | | | | |
| 1974 | 13,966 | 100.0 | 402,769 | 100.0 |
| 1973 | 13,328 | 100.0 | 578,927 | 100.0 |
| 1972 | 9,931 | 100.0 | 447,756 | 100.0 |
| 1971 | 8,736 | 100.0 | 210,465 | 100.0 |
| 1970 | 3,711 | 100.0 | 363,166 | 100.0 |

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[a] Other locations are inland waters, open waters, and high seas.

[b] Coastal waters - within 3 miles of shoreline.

[c] Contiguous zone - 3 to 12 miles from shoreline.

Source: U.S. Department of Transportation, Coast Guard, "Polluting Incidents In and Around U.S. Water," Washington, D.C.: 1971-1974).

## 3. Impacts of Marine Oil Spills

### 3.1 Seabirds

Among the most visible and publicized effects of marine oil spills are the contamination and fouling of birds. Contact with an oil slick can cause loss of insulation, disrupted feeding behavior, and even direct poisoning in many species of waterfowl and seabirds. Fouling of feathers is perhaps the most serious effect in terms of total impact on birds. When a bird's feathers become coated with oil the small feather barbules are rumpled and disheveled, so that they offer less insulation and buoyancy. The most severe results of this coating are pneumonia due to loss of body heat and, in some cases, actual drowning due to loss of buoyancy.[14] Even when the impacts of fouling by oil are not quite so acute, the excessive preening which it induces can lead to the disruption of normal feeding habits and the ingestion of oil. This latter effect, in turn, causes poisoning and inflammation of the digestive tract which, along with body heat losses, can further reduce feeding activity and lead to starvation. There is also some evidence that coating by oil clogs the salt glands by which many birds convert salt water to freshwater; the result can be fatal dehydration.[15]

Susceptibility to these physiological effects varies among different species of birds. Diving birds such as auks (murres, guillemots, razorbills, puffins, etc.) and diving ducks (scoters, scaup, eiders, golden eye ducks, long-tailed ducks, etc.) are generally most susceptible to the effects of contamination and fouling, and for this reason they often account for an inordinate number of the mortalities associated with oil slicks.[16] These birds spend most of their lives on or near the surface of the ocean: they dive for their food; they are often weak fliers, and many of them dive under the water rather than fly out of it in response to disturbances or immediate threats. Also, many of them tend to congregate in flocks, so that serious population depletion can occur as the result of an oil spill near their habitats. There also have been reports that some species of birds are actually attracted to oil slicks;[17] if this is indeed the case, then these species certainly face a serious threat from oil spills in areas where they are common. Some species, most notably seagulls and shearwaters, seem to avoid slicks; naturally these species account for very few of the mortalities associated with oil spills.

A major danger posed to bird species by oil spills at sea is severe population depletion which can result either when the spill is in close proximity to the habitat of a gregarious species or when the spill occurs along the path of migrating flocks of birds. In both of these circumstances, large numbers of birds are concentrated in a relatively small area, so that a slick covering only a small area can affect many individuals. Moreover, many bird species undergo significant natural population fluctuations. Although these fluctuations can normally be absorbed without threatening the species when populations are at healthy levels, sudden and severe depletions in populations can endanger some species by rendering their populations less resilient to natural stresses.

Up to now it has been frustratingly difficult to assess with any accuracy the extent of the impact of a given oil spill on bird species. Bird death tolls are normally estimated by counting the number of dead birds which wash up onto shores near a spill. Unfortunately, as few as 5 to 15 percent of the dead or moribund birds impacted by an oil spill can be expected to wash ashore,[18] so that recorded death tolls are often gross underestimations of the actual mortality caused by spills. Table D-6 lists several important spills which have occurred in or near United States coastal waters and estimates -- based on actual counts and not on guesses concerning the percentage of mortalities observed -- of the number of birds affected.

It should be noted that large slicks in more or less open seas seem to pose a greater threat to seabirds than do slicks nearer to shore. In coastal areas, seabirds are able to escape coating by oil simply by moving inland or, since some spills are contained in bays or coves, by moving a short distance along shore. On the open sea, by contrast, extensive and rapidly spreading slicks are difficult for seabirds to avoid and may even be more difficult for them to distinguish from normal, calm waters.

### 3.2 Fish

Fish enjoy two major advantages in overcoming the adverse impacts of oil contamination. Evidence suggests that one of the reasons for the superior survival ability of fish, as compared to, say, seabirds, when faced with oil pollution is the fact that fish simply migrate from the affected areas before being subjected to prolonged oil exposure. Also surfaces of the fish, including the gills, are coated with a slimy mucus that partially repels oil and therefore protects them.[19]

Damage to fish populations as a result of a specific oil spill can nevertheless be extensive, depending on the particular circumstances of the spill. The January 1969

## TABLE D-6

## SELECTED OIL SPILL-RELATED BIRD MORTALIITES IN THE UNITED STATES

| LOCATION | NO. OF BIRDS AFFECTED (APPROX.) | NATURE OF SPILL | SIZE OF SPILL (bbl) | YEAR |
|---|---|---|---|---|
| SANTA BARBARA, CALIFORNIA | 3600 | CRUDE OIL FROM OFFSHORE PLATFORM | 18,500 | 1969 |
| OFFSHORE LOUISIANA | NONE | CRUDE OIL FROM OFFSHORE PLATFORM | 36,000 | 1970 |
| TAMPA BAY, FLORIDA | 3500 CONTAMINATED | BUNKER C OIL FROM TANKER *DELIAN APPOLLEN* | 240 | 1970 |
| MARTHA's VINEYARD MA. | 1000 CONTAMINATED | WEATHERED OIL | NOT GIVEN | 1970 |
| KODIAK ISLANDS ALASKA | 96,000 | UNSPECIFIED OIL SPILL | NOT GIVEN | 1970 |
| OFFSHORE LOUISIANA | NONE | CRUDE OIL FROM OFFSHORE PLATFORM | NOT GIVEN | 1970 |
| SAN FRANCISCO BAY, CALIFORNIA | 6000 | BUNKER C FROM TANKER *OREGON STANDARD* | 45,000 | 1971 |
| OFFSHORE LOUISIANA | NONE | CRUDE OIL FROM OFFSHORE PLATFORM | SEVERAL SMALL SLICKS | 1971 |

SOURCE: U.S. Dept. of the Interior, Bureau of Land Management. *Final Environmental Impact Statement on OCS Sale No. 33* (Offshore Louisiana). 1974.

"blowout" of Well A-21 at Santa Barbara, California decimated some elements of the seabird population (notably loons and grebes),[20] yet no apparent effects on fish were reported. Nine months later, in September 1969, a spill of 4,500 barrels of No. 2 fuel oil killed an estimated 95 percent of all fauna including fish along a 3-mile shoreline at West Falmouth, Massachusetts.[21] In part, this higher mortality was due to the higher toxicity and greater soluble fraction of the refined No. 2 oil as compared to the crude Bunker fuel released in the Santa Barbara spill. It also appears that spills in closed regions, such as Wild Harbor in West Falmouth, predominantly affect fish which become trapped by the contamination. On the other hand, spills in the open ocean, such as the Santa Barbara spill, result in greater damage to sea birds. In the case of the Torrey Canyon spill in the English Channel, the effects upon the fish were augmented by the use of toxic dispersants. After the Torrey Canyon spill 50 to 90 percent of the pilchard eggs were found to be dead and the young pilchard population was apparently decreased. The vulnerability of spawning grounds to oil contamination represents a major part of the threat to fish posed by oil spills. While pilchard eggs are endangered by exposure to oil because they float on the surface, some eggs are in particular danger due to their position in the sea bed, where oil eventually settles.

Several fish are endangered by their habitual proximity to the ocean surface where unweathered and, often, weathered oil is concentrated. Larval fish may be affected either by toxicity or by entrapment ("oiling").[22]

Beyond the lethal effects of high oil concentrations there are many important and possibly widespread sub-lethal effects. Laboratory experiments by Brockson and Baily[23] to determine the impact of benzene upon the respiration of juvenile salmon and striped bass demonstrate this type of phenomenon. Respiratory rate was found to increase as a direct result of exposure to 5 to 10 ppm of benzene for 24 to 48 hours and decreased to normal after approximately 6 days of recuperation in clean water. The ability of fish to decontaminate their systems subsequent to absorption of general hydrocarbons is not clear, however, and may depend strongly upon the specific species and hydrocarbon in question. In addition to effects on respiration and direct contamination of fatty portions of fish by hydrocarbons, certain behavioral changes are found to occur as a result of oil pollution. For instance, bullheads, which display complex and chemically-mediated social behavior, have been shown to develop intense conflict behavior when exposed to water-soluble factions of Kuwait crude oil.[24] Fish are believed to detect food or prey through the chemoreception of specific compounds at concentrations in the part per billion range, which is comparable to the concentrations produced by the dissolution of oil slicks. Therefore another harmful result of a spill may be the blocking of the chemoreception capabilities.[25]

Probably the best area for studying the effects of chronic oil pollution upon fish is the Louisiana coast, where an estimated 60 million barrels of oil have been gradually dispersed over the past 30 years.[26] The Louisiana coast is simultaneously a major oil-producing region of the United States and a rich fishing bank. This chronic contamination does not appear to have reduced the productivity of major fisheries and therefore suggests that many populations in offshore regions can survive long term, low level intrusion of oil. At present there is a dearth of reliable field research in this area, however, and many studies of chronic pollution have been discredited for failing to demonstrate that variations in fish populations cannot be explained by other factors such as salinity and intensity of fishing activity.

### 3.3 Marine Mammals

The impacts of oil spills on marine mammals are possibly the least known of the whole marine biotic community. The relative scarcity of marine mammals and subsequent difficulty of observing and quantifying effects after an oil spill are the probable reasons for this lack of comprehensive information. However, three causes of oil-related deaths have been suggested in the literature: poisoning from ingested oil, suffocation, and altered insulation properties of fur. While the literature reviewed cited several examples of deaths after oil spills, the exact causes of death were never stated authoritatively. However, the deaths were always thought to be a result of one of the three causes listed above.

A mammal has impervious skin and breathes air, so the entrance of toxic oil materials into the system is primarily limited to ingestion during feeding or grooming. It is believed[27] that one of the more serious problems of ingesting oil would be the effects of active hydrocarbons on the sensitive, highly developed nervous system of mammals which is sheathed in fatty material. The most severely affected species would probably be the fur-bearing mammals (sea lions, otters, muskrats, etc.) attempting to clean oil off their coats. It is also likely that whales in areas near a spill could ingest dispersed oil while filter-feeding on planktonic crustaceans. At the time of the Santa Barbarba blowout, grey whales were passing through the area on their annual migration. However, they reportedly diverted their path from the highly polluted area, explaining the fact that no more corpses washed up on shore during 1969 than in previous years.[28] Also during the Santa Barbara oil spill many sea lion pups were observed to be coated with oil. While no more deaths were observed than usual, if the spill had taken place when the pups were feeding, the number of deaths would probably have been significantly above that normally observed.

Oil-caused suffocation is a highly plausible occurrence since all marine mammals must surface for air, and if done in a spill area, the respiratory openings can be clogged with oil. There is one unsubstantiated report that dolphins were stranded on shore after the Santa Barbara blowout with their blowholes plugged with oil and lungs damaged. After a spill of fuel oil at Chedabacto Bay, Nova Scotia, 150 harbor seals were observed, some heavily coated with oil. The most affected areas were those which are exposed: eyes, ears, mouth and nose. About 5 percent of the seals were found dead, with death being attributed to suffocation.[29]

Mammals are warm-blooded organisms and those living in the ocean must usually maintain their body temperature above that of the surrounding water. While cetaceans (whales, dolphins) have an insular fat layer, pinnipeds (seals, walruses), sea otters, muskrats and others also rely on a thick fur coat. Oil can affect the insulating properties of fat by reducing its waterproofing ability. If the body temperature is sufficiently below normal, the susceptibility to disease is greatly increased. This can be a significant problem since "apparently, marine mammals fail to recognize an oil slick until coating is inevitable."[30] The opposite problem, that of overheating (in seals), has been suggested as a result of seals lying on rocks in strong sunlight with a thick, dark coat of oil on their fur.[31]

The impacts of oil spills on marine mammals can be quite serious. At present little is known. This can be attributed in part to the fact that marine mammals are not densely populated in comparison with fish and plant populations. Although few mammals have been found dead as a result of past oil spills, it is entirely possible that a significant number of corpses fell to the ocean's bottom or were swept far out in the sea.

### 3.4 Plankton

The term "plankton" is used as a general designation for the large and varied class of tiny, sessile organisms which float or drift near the surface of the ocean. Plankton are generally divisible into two major categories: the plant-like species, or phytoplankton, and the animal-like species, or zooplankton. Phytoplankton exist in huge quantities in the ocean; many of them are microscopic algae. They serve as primary producers in the marine ecosystem, converting water and carbon dioxide to organic matter by photosynthesis. For this reason, they are restricted primarily to the euphotic zone -- the top 200 meters or so of the water column where sunlight is able to penetrate. Like other plant species, phytoplankton bloom in the spring as the water becomes warmer, and their growth declines in the autumn when the water grows cooler. Zooplankton form a highly diverse set of organisms which graze predominantly on phytoplankton. Zooplankton can be divided into holoplankton, or organisms such as copepods and tunicates which spend their entire life cycle as plankton, and meroplankton, which consist primarily of floating eggs, larvae, and juveniles of larger nektonic or benthic fishes and shellfishes. Phytoplankton and zooplankton together comprise a very important basis for the marine food web.

The effects of oil on phytoplankton have been investigated widely, but the difficulties of studying tiny, sessile organisms in their natural environment have yielded conclusions which are somewhat sketchy at best.

Some laboratory studies have indicated that exposure to high concentrations of petroleum compounds, especially the lighter fractions, suppresses the productivity of diatoms,[32] an important class of phytoplankton characterized by siliceous cell walls. One cause of this suppression may be the inhibition of photosynthesis, an effect observed in laboratory studies of oil effects on other phytoplankters. Using what they felt to be typical oil spill-associated hydrocarbon concentrations, Gordon and Prouse found that No. 2 fuel oil stimulated phytoplankton photosynthesis slightly at concentrations between 10 and 30 ppb while concentrations between 100 and 200 ppb suppressed photosynthetic activity as much as 60 percent.[33] There is evidence that phytoplankters are more sensitive to No. 2 fuel oil and other light fractions than to the less soluble oils.[34] The mechanisms most often proposed for photosynthesis inhibition are reduced light penetration beneath slicks and the intrusion by petroleum hydrocarbons into the membranes of the cells and mitochondria and subsequent disruption of the cells' permeability characteristics.[35,36]

A major problem with such laboratory studies is that their results are difficult to interpret in the context of ocean spills because the concentrations of hydrocarbons to which various phytoplankton are typically exposed in or beneath an oil slick are largely unknown. Extensive investigations following the Santa Barbara blowout of relatively insoluble crude oil revealed no conclusive evidence of reductions in phytoplankton productivity which could be directly attributed to petroleum. (Interestingly, evidence suggests that the use of chemical dispersants on the slick did have adverse effects on productivity.)[37] It is only fair to note, however, that since phytoplankton are sessile and are therefore passively carried around by water currents, slick-related effects may be difficult to observe in the field. In any case, most phytoplankton multiply rapidly, and as a result their communities seem to be resilient enough to withstand occasional large oil spills. The effects of chronic oil pollution on phytoplankters remain poorly known.

Although studies on the effects of oil spills on zooplankton are less common than for phytoplankton, investigators generally agree on several basic observations. To begin with, zooplankton tend to be more susceptible to toxic effects and direct mortality resulting from exposure to oil compounds than most phytoplankton. Also, holoplankton seem to show greater sensitivity to oil pollution than meroplankton, which in turn are more vulnerable than their respective adult forms.[38] Although holoplankters have been observed to ingest and void particles of spilled Bunker C (a very heavy oil) without noticeable effects,[39] these zooplankton are eaten by small fishes and filter feeders, and the impacts of holoplankton-ingested oil on the marine food web are as yet unclear. On the other hand, planktonic herring eggs exposed to crude and fractioned oil slicks have shown high (70 to 100 percent) mortality rates, and eggs which survived hatched a large proportion of deformed larvae.[40] These effects can impose severe local impacts on fish populations near a spill.

In summary, the impacts of spilled oil on plankton are not as dramatic as those on larger organisms higher up in the food chain. Although suppressed photosynthetic rates have been observed in phytoplankton exposed to oil, and similarly exposed zooplankton exhibit some toxic responses, especially toward the more soluble fractions, natural plankton communities seem able to recover quickly from large accidental oil spills. However, impacts of bioaccumulated oil ingested by plankton are still unclear, and the effects of chronic exposure to oil pollution are not well understood.

### 3.5 Neuston Community

The neuston community can be defined as the collection of organisms which live primarily in the surface film of the ocean. Although this community is composed of organisms discussed in many other sections of this chapter it merits specific attention because of the significant impact of an oil spill upon surface organisms. The neuston community includes the floating eggs of such fish as pilchard, mackerel, and some herrings; Sargassum; plankton; the juveniles of many fish, squid, and other nectonic (water column-inhabiting) forms; and other organisms. One familiar example which can be considered neustonic in the context of oil impacts is the mosquito larva.

Meroplankton (planktonic for part of their life cycle) are generally considered to be sensitive to environmental stress[41] and since many are neustonic they are particularly endangered by oil spills.

Occasional substantial catch declines in menhadden and other fishes in the Gulf of Mexico have been attributed to abnormal weather and Mississippi floods. It is believed that the large-scale destruction of neustonic eggs is responsible for the reduction, although this hypothesis remains unsubstantiated at the present time.[42] If it is correct, then it seems likely that an extensive oil spill could have significant adverse effects upon the fish catches by decimating the neustonic eggs and larvae. These could be exposed to direct kill from water-soluble fractions of hydrocarbons and would also be vulnerable to starvation in the event that a massive spill killed off their food supply of phytoplankton and zooplankton.[43] Since larvae are experimentally known to be far more sensitive to oil pollution than associated adult populations, exposure to oil spills in this critically vulnerable point in the species' life cycle could substantially reduce populations in succeeding years.

Another hypothetical danger concerns the seaweed Sargassum and its associated community. A large spill of crude in the vicinity of one of these floating assemblages could result in oiling of the Sargassum producing a 'matted', stable aggregation of oil. This could well lead to the decimation of the community which relied upon the healthy Sargassum for survival.[44] While the ecology of the Sargassum community is poorly known, the community is highly specialized and is therefore likely to be less vulnerable to the type of stress represented by a major oil spill.

A further oil-spill related danger to the neuston community is the tendency of oil to concentrate chlorinated hydrocarbons, including DDT, in a thin layer near the surface. Field measurements by Seka and Cochrane (1969) in Biscayne Bay, Florida, demonstrated this by determining that the concentration of dieldrin, a chlorinated hydrocarbon used as a pesticide, in the top 1 millimeter of water containing a slick was more than 10,000 times higher than the underlying water. And since the dieldrin in this millimeter was presumably concentrated in the top 1,000 angstroms containing the slick itself, the surface concentration was about 1 part in 10,000, as opposed to the underlying water concentration of 1 part in a trillion.[45]

One final disturbing aspect of the neustonic problem is that conventional methods of pollution removal may do little to aid these communities other than to prevent the spreading of the affected zone. For example, the use of booms, which is recognized as a preferred alternative when weather conditions permit their use, would appear to clear away much of the neuston along with the contamination. Burning the slick will clearly put stress upon the neustons, as will the use of dispersants, which are generally highly toxic. Conceivably, chalking the slick and thereby sinking it might save some of the surface communities, yet the resultant damage to bottom dwellers raises serious questions about the viability of this approach.

### 3.6 Benthic Community

The benthic (seabed) community is composed of gastropods (snails, limpets, etc.), bivalves (clams, mussels, etc.), crustaceans (shrimp, lobsters, etc.), various forms of algae, kelp and other flora, as well as other forms such as worms and anemones. These species are endangered by oil spills since large amounts of oil ultimately settle from a surface slick to the bottom in many instances. These can lethally affect the benthic species by coating, toxicity, or over-weighting so that bottom currents can transport the species out of their accustomed habitats. Sublethal doses of petroleum toxins can also adversely affect the community by limiting growth and reproduction.

Oil sinks naturally to the bottom by adhering to clay minerals, particles coated with organic material and other particles which occlude the slick. In the case of the "blowout" of Platform A-21 at Santa Barbara, California, land runoff turbidity supplied the necessary particulates.[46]

Oil from the Torrey Canyon spill was sent to the bottom by the deliberate application of 3,000 tons of chalk off the coast of Brittany.[47]

The oil deposited by the Santa Barbara blowout has been transported by bottom currents from the original Platform A-21 site into the Santa Barbara basin where the large-scale pollution is not likely to degrade rapidly due to low oxygen conditions.[48] This spreading of the original contamination is not uncommon. The No. 2 fuel oil spilled at West Falmouth in 1969 has also drifted into deeper waters. Once again, the mode of transport seems to be the movement of oil-laden sediment along the bottom.[49]

Oil on the bottom appears to weather very slowly. The Santa Barbara blowout commenced on January 28, 1969. Successive measurements of sediment pollution on March 31, May 1, and June 13, 1970 showed no evidence of a reduction in oil content over this period.[50] Sediment oil is generally rich in aromatics and cycloalkanes due to selective biodegradation and other weathering losses of the n-alkanes.[51] Unfortunately these aromatics include some of the most toxic components of the crude oil. The weathering process is retarded by the fact that sediments loaded with oil become anaerobic so bacterial degradation and reworking of the sediments by aerobic benthic organisms is arrested.[52] Furthermore, oil is known to soak into the sediment and weather even more slowly in this sheltered environment. The West Falmouth spill occurred in September of 1969. In April of 1971 the sediment oil was found to be abnormally high in aromatics (30 percent), having undergone selective weathering, and had penetrated 3 inches into the sediment. Evidence from this incident supports the theory that absorbed oil degrades more slowly than that on the surface of the seabed. Only after two years had absorbed oil been found to have weathered to the stage that surface sediment oil achieved in 10 months.

Presently there is little knowledge about the effects of oil deposits upon hard substrates as opposed to the soft, mucky or sandy sediments previously discussed.[53] Presumably there would be less soaking and more rapid weathering, but more field work needs to be done in this area. There are many of these rocky outcroppings, notably in the oil-rich offshore regions of Texas.

The biological effects of oil upon benthic communities have received considerably less attention than the impacts upon the surface dwellers. However, some field work and experimentation have been done which provide a partial understanding of the potential threat to the benthic communities. The Torrey Canyon spill is particularly interesting because an estimated 23,500 tons of oil was sunk by the application of chalk. Skin divers did a post-spill study of larger benthic organisms, noting large numbers of dead and moribund clams, snails, crustaceans, and echinoderms. Unfortunately much of this is attributed to the use by English authorities of BP-1002, a highly toxic dispersant, on the eastern portion of the slick in lieu of the French choice, chalk. Little is known about the fate of the oil that was sunk other than the fact that it has subsequently fouled fishing gear and contaminated catches.[54]

A survey of the effects of the Santa Barbara blowout was aided by the existence of a baseline study of the benthic community 10 years prior to the contamination. Although there was shown to be considerable reduction of biomass during the period from the baseline study to the post-spill study, it may be possible to account for the change by considering heavy rainfall, the presence of drilling operations and other spills in the channel not existing during the baseline study, an increase in the concentration of land-derived pollution (e.g., sewage and pesticides), and natural fluctuations.[55] Specific high levels of damage to the echuinoid worm Listriolobus pelodes[56] and the small seaweed Hesperophycus harveyanus were noted, with the latter being attributed to erosion by wave-action upon the overweighted plants.[57]

The spill at West Falmouth has undergone intensive study due to its proximity to the Woods Hole Oceanographic Institute. Although it was initially localized, the oil has subsequently drifted, producing a gradient of oil concentrations. In heavily oiled areas the benthic community was virtually totally eliminated. In other less contaminated regions the sensitive species such as amphipod crustaceans were selectively killed.[58] The immediately apparent lethal effects (the shore became littered with washed up lobsters and other crustaceans) were accompanied by other sublethal effects. In particular it was noted that fiddler crabs displayed out-of-season mating coloration and altered defensive behavior.[59]

The persistence of sediment oil is demonstrated by the spill in Chedabucto Bay, Canada, of Bunker C fuel. While there was only a very limited number of fatalities, contamination was identified at the spill location 26 months after the original accident.[60] Woods Hole scientists estimate complete recovery of the West Falmouth spill also to be a long process, on the order of 5 to 10 years.[61]

The *Tampico Maru* spill caused extensive kills of Pismo clams, abalones, starfish, sea urchins, lobsters, and other subtidal benthic invertebrates. Since much of the oil became concentrated in a relatively sheltered cove the long-term effects of the reduction of grazing species (sea urchins) and predators altered the ecosystem significantly. Full recovery had not occurred as much as 7 years after the spill[62] with the abalone *Haliotis fulgiens* and the mussel *Mytilus* still appearing in reduced numbers.[63]

Experimental work has begun to determine the lethal threshholds and sublethal effects of oil on benthic species. Among the fauna, gastropods (snails, limpets, etc.) are found to be the most resistant to contamination while crustaceans (lobsters, shrimp, etc.) are the most sensitive. Gastropods can survive up to 100 to 200 ppm of soluble aromatic derivatives (SAD, a major toxic component of oil) and this is attributed to their secretion of a mucous substance which combats coating. Bivalves, such as mussels and clams, display a moderate resistance, surviving up to 5 to 50 ppm SAD. They defend against oil by closing their shells, but since they cannot do so indefinitely, they are moderately susceptible to toxins. The remaining species, crustaceans and others are generally killed by 1 to 10 ppm SAD.[64]

Cockles suffer high mortalities after a short exposure to toluene or mixed aromatic solvents and the American freshwater crayfish is eliminated from irrigation channels by a herbicidal mixture of aromatics, rich in xylene, in concentrations of 150 to 300 ppm. 740 ppm kills Canadian Pond weed, barnacles (*Eliminus modestus*) suffer 50 percent mortality after 1-hour exposure to 100 ppm fresh crude, and a 3 to 4 percent mixture of fuel oils is lethal to oysters and mussels in one week.[65]

BP-1002, the dispersant used in the *Torrey Canyon* incident, is lethal to a variety of crustaceans, sub-littoral molluscs, and delicate seaweeds at concentrations of 5 to 25 ppm and can affect the growth of the larvae of barnacles and tube worms at 0.5 to 1.0 ppm.[66]

While these concentrations are fairly high they are evidently reached in the actual field conditions upon occasion as is demonstrated by the lethalities associated with the aforementioned spills. Many sublethal but nonetheless important effects have been noted at far lower and hence more common concentrations. Experiments with lobsters have shown that they may be attracted to bricks soaked in soluble aromatic components of kerosine,[67] that kerosine contamination induced searching, feeding and agitated grooming behavior,[68] but that in the presence of small quantities of crude oil, motivation for feeding was lowered.[69] Along those lines Kitteredge (cited in Johson and Barton, 1973) has demonstrated that the feeding and sex pheromone responses of the lined shore crab Pachygrapsus crassipes are inhibited by dilute concentrations of diethyl ether extracts of crude oils.[70] Starfish are known to react to oyster extracts in concentrations of ppb.[71]

Many studies have investigated the depressant effects of crude upon the respiration of various species. Depressed respiration has been used as an indication of environmental stress. Boesch, however, states:[72]

> Perhaps more important than respiration alone, is the effects of oil on the maintenance of a carbon balance sufficient for growth and reproduction. Gilfillian (1973) exposed the mussels Mytilus edulis and Modiolus demissus to seawater extracts of a crude oil and found that while respiration was not greatly affected, both the amount of carbon consumed and the amount assimilated decreased sharply at concentrations of greater than 10 percent (concentrations of 1 ppm or less). Thus, the net carbon balance (assimilation less respiration) declined to negative values in several experiments, meaning that energy was less available for growth and reproduction.

The discovery that hydrocarbons, ingested by marine organisms through the wall of the gut, can become part of the lipid pool[73] and then be passed up the food web raises the possibility of the concentration of oil toxins eventually leading to human consumption. At present evidence of hydrocarbon accumulation is not strong, however, and does not pose the same threat as that of pesticides.

There is considerable controversy about the process and rate of depuration of contaminated species. Blumer, Souza, and Sass (1970) claimed that oysters removed from an oil-polluted area and kept in clear water for 6 months had no cleansing occur. Lee, Sauerherber and Benson (1972) reported that the mussel Mytilus edulis rapidly incorporated petroleum hydrocarbons, e.g. 3, 4 benzopyrene, but that they remained in the gut and were neither assimilated nor broken down. In contrast to the results of Blumer, Souza, and Sass, they were quickly cleansed in clean water.[74]

In carefully controlled experiments upon the clam Rangea cuneata and the oyster Crassostrea virginica, Anderson clearly demonstrated that these bivalves do absorb significant quantities of aromatics and saturated hydrocarbons with a higher intake of the former being noted. He concludes:

> However, the findings presented in this study have demonstrated that both aromatic and saturated hydrocarbons are released from the tissues relatively rapidly, such that maintenance in clear water for periods from 24 to 52 days is sufficient to cleanse the tissues of detectable levels of hydrocarbons.[75]

No. 2 fuel was shown to be more persistent than Louisiana crude, as it depured in 52 days while Louisiana crude was eliminated from the oysters in about a week.

While the preponderance of evidence indicates that depuration, in *clean water*, occurs fairly rapidly, the fact that oil is found to be so persistent on the bottom means that oil spills must be considered as a serious, if localized, long-term threat to the benthic communities.

## 3.7 Estuaries, Wetlands and Intertidal Zone

Shore and coastal zones may be roughly divided into wetlands, intertidal zones, and estuaries. Each has its own unique physical and biological characteristics, and responds accordingly to oil contamination.

Estuaries (mouths of rivers) exhibit periodic fluctuations in salinity from the rise and fall of the tide. There is also a general salinity gradient between fresh and sea water, giving rise to a stratification of floral and faunal types. Estuaries are often centers for industry, shipping, and commercial fishing subject to chronic stress from pollutants arising from these sources.

The wetlands in temperate zones generally take the form of low-lying marshes, which are periodically flooded with brackish water at high tide. Marsh grasses such as *Spartina* usually dominate.

Wetlands and estuaries are among the most productive areas in the world. Odum[76] found estuaries to have a primary productivity of 10 to 25 grams of dry matter per square meter per day. Salt marshes produce up to 9 grams, shores and shallow seas 0.5 to 3.0 grams, and the oceans less than 0.5 grams/meter$^2$/day. Much of the life in estuaries is supported through a food web based on vascular plant debris (detrius) from the surrounding wetlands.[77] Tidal wetlands and estuaries serve as habitat, feeding, and breeding grounds for shore birds, fish, and other wildlife. Wetlands are important defenses against erosion.

Oil spills in estuaries have tended to be chronic rather than spectacular, and probably for this reason the biological effects have not been extensively studied.[78] Certain characteristics of estuaries indicate that oil pollution may have serious effects:[79]

1. Estuaries are generally confined and relatively shallow bodies of water. Oil spills and the emulsifiers used to disperse them will be concentrated in a relatively small area and volume, and may remain so for long periods if the river feeding the estuary is sluggish and tidal volume is small.

2. Estuaries are typically turbid, with the result that floating oil adheres to the fine sediment particles and sinks to the bottom, where it contaminates shellfish and bottom-feeding fishes. Fine silt tends to be accumulated in estuaries by the net vortex action of freshwater moving seaward over the top, and sea water moving in closer to the bottom.

3. A major food web in most estuaries is based on detritus, which absorbs oil.

4. Oil may persist and accumulate for long periods under the anaerobic conditions of the subsurface sediments.

5. Diversity is low at the head of an estuary, as relatively few species are adapted to high turbidity, fluctuations in salinity and the unusual combination of salty water and muddy soil. The region may become barren if none of these species proves resistant to the pollutant.

On the other hand, estuaries may prove themselves particularly resilient because:

1. The abundant microbial life should lead to rapid aerobic degradation.

2. Life-forms in estuaries tend to have high reproductive capacities, enabling them to recover quickly even after large numbers are killed.

Milford Haven (South Wales) has become a major oil port within the last 15 years. It has particularly good clean-up facilities and well-defined plans to ensure their rapid and efficient use. It has the advantage that the larger tidal volumes and swift currents allow the use of emulsifiers which would be too toxic in a more sluggish estuary.[80] Milford Haven has a rich marine flora and fauna, including commercial shell- and fin-fisheries,[81] and reports that no general deterioration could be detected as a result of the first decade of operation.

The effects of oil spills on tidal wetlands have been well documented, especially with regard to the vascular plants. The studies generally agree that while the wetlands are quite resistant to single spills, and recover quickly,[82] they can be severely damaged by chronic pollution.[83]

Salt marsh plants are generally terrestrial species adapted for marine conditions. In the lower reaches of a marsh, their diversity is low, and a bad spill may not leave behind sufficient vegetation to prevent erosion.[84] In the higher regions, resistant species such as Agrostis stolonifera can spread across the bare patches.

Nelson-Smith[85] suggests that oiled salt marshes are best left untreated because they trap and hold the oil, effectively preventing it from fouling other regions. They are generally unsuited to recovery of the oil by pumping, due to the soft and unstable ground, and their vegetation is susceptible to emulsifiers used to disperse oil. The intertidal zone consists of the area between high and low tide, which is alternately exposed to sea and air. The dominant species vary depending on whether the beach is rocky, sandy, or muddy. Rocky shores have been most extensively studied, perhaps because the organisms are most easily detected and observed.

Oil washed up on sheltered sandy beaches seems to have severe effects. Oil spills at West Falmouth[86] and Chedabuck Bay[87] remained in the intertidal zone for several years. Oil does not readily penetrate wet sand, but wave action may cover it with fresh sand, giving even a newly polluted beach a clean appearance.[88] The oil may seep out or be exposed at a later date, and cause continued damage to local lifeforms.

On a rocky beach, oil is either stranded at the high-water mark, or washed back out to sea by the waves. Oil left at the high-water mark may seep into cracks and cause long-term damage,[89] or it may mix with mineral and organic matter to form hard, tarry balls.

Intertidal organisms are rarely killed by direct toxicity.[90] More commonly, they are anesthetized or weakened, and later swept from their natural habitat or eaten by predators. Some mobile intertidal animals are trapped by particularly thick oils.[91] Sessile organisms such as barnacles may be suffocated when completely covered. A covering of oil also reduces the gas exchange rate somewhat[92] and may cause tidal pools to overheat in direct sunlight as a consequence or its darker color. It may inhibit photosynthesis simply by blocking the sunlight.

Recolonization of a denuded rocky coast generally follows the succession pattern of a freshly-introduced surface. Green algae return first and grow in profusion due to the absence of grazers. These will be replaced by brown, fucoid algae, often slowly crowded out by mussels and barnacles. Recovery is completed with the re-establishment of the algae/herbivore balance, which takes at most a few years.

Recovery on a rocky coast is usually fairly rapid. This may be attributed to the fact that oil rarely persists in the intertidal zone, but is swept out to sea or remains at the strand-line and intertidal organisms reproduce rapidly and in large numbers. Many of the plant species can regenerate rapidly from small living portions.

Biologists generally agree that the use of emulsifiers on stranded oil may cause more damage to the intertidal community than the oil alone. Lower-toxicity emulsifiers such as BP1100 have been developed in recent years, and much of the reported damage from them is attributable to improper application.

## 4. Extent, Location and Frequency of Terrestrial Oil Spills

Oil spills on land arise from three basic sources: pipelines, trucks, and trains. Of these, spills from trains are least significant, since only a small portion of oil transported overland is carried by trains; trucks are of moderate significance but are used mainly to transport refined oil and, because of their size, are responsible only for relatively small spills. Pipeline spills account for most of the substantial oil spills on land. Also pipeline spills are responsible by far for most of the crude oil spilled on land. Table D-7 displays the record of crude oil spills from pipelines in recent years.

In 1975, for example, 225 accidental pipeline spills occurred in the United States. Of these, 135 involved crude oil, accounting for over 33 percent (105,871 bbl) of the total volume of petroleum products spilled from pipelines. Most (74 percent) accidents occurred in the line pipe itself, as a result of ruptures caused by machinery and external or internal corrosion.[93]

From 1972 to 1974, a total of 1,444,261,400 tons, or about 9,552,000,000 barrels, of oil were transported by pipeline. Department of Transportation (DOT) figures (see Table D-7) show that in this same period, 610,801 barrels were lost in 501 separate incidents, or 1 barrel for every 15,600 barrels transported. As total barrel-miles for this period were 5,870 billion,[94] this amounts to 1 barrel for every 9,610,000 barrel-miles.

The DOT figures show that 31 of these spills were large (5,000 barrels or more), while 470 were less than that amount. Texas, Oklahoma, Kansas, and Louisiana accounted respectively for 37 percent, 11 percent, 6 percent, and 5 percent of the incidents.[95] As would be expected, these states have the heaviest pipeline activities.

## 5. Impacts of Terrestrial Oil Spills

Terrestrial spills which do not impinge on the local water system are generally much less damaging than marine spills of comparable volume. The contaminant spreads neither so fast nor so far, with the result that much of it can be recovered simply by suction. The damaged soil may be removed and replaced with fresh soil, turned under, or seeded with bacteria to promote degradation.

## TABLE D-7

## CRUDE OIL PIPELINE ACCIDENTS REPORTED TO THE DEPARTMENT OF TRANSPORTATION ON DOT 7000-1(1)

| YEAR | NO. OF ACCIDENTS | LOSS (BARRELS) | PROPERTY DAMAGE ($) | NO. OF ACCIDENTS DUE TO CORROSION |
|---|---|---|---|---|
| 1968 | 322 | 222,257(2) | 866,072 | 168 |
| 1969 | 246 | 174,640(3) | 1,176,260 | 129 |
| 1970 | 216 | 383,160 | 413,756 | 133 |
| 1971 | 172 | 115,760(3) | 117,938 | 77 |
| 1972 | 180 | 233,690(4) | 760,798 | 76 |
| 1973 | 155 | 208,373(5) | 411,080 | 65 |
| 1974 | 166 | 168,738(6) | 635,666 | 51 |
| 1975 | 135 | 105,831 | 1,441,764 | 54 |

(1) Dept. of Trans., Materials Transportation Bureau. Summary of Liquid Pipeline Accidents Reported on DOT From 7000-1. 1968-1975.

(2) Includes 1 accident with loss of 41,000 barrels and 1 with loss of 12,363 barrels.

(3) Includes 5 accidents where loss was 5,000 barrels or over.

(4) Includes 14 accidents where loss was 5,000 barrels or over.

(5) Includes 10 accidents where loss was 5,000 barrels or over.

(6) Includes 7 accidents where loss was 5,000 barrels or over.

Deneke et al. (1975) have reviewed the literature on the effects of oil on plants in temperate zones. They conclude:

> ... in oil-contaminated soils microbial populations are changed; total number of microbial species decreases while the total numbers of organisms increases... With respect to changes in physical soil characteristics that initially occur, organic matter is increased, soil particles become disaggregated and dispersed, soil aeration is decreased and water wettability is interfered with. However these conditions generally improve with time. Chemical changes include: (1) the creation of reducing conditions, (2) the forcing of soil pH towards neutrality, (3) a decrease in the oxidation-reduction potential of the soil, (4) an increase in the solubility of iron, (5) an increase in available manganese, (6) an increase in nitrate production, and (7) an increase in available phosphorus.
>
> It is felt that one reason for the decline and death of plants in petroleum-saturated soils is the manganese toxicity resulting from its increased availability. It is also known that seed germination is delayed or inhibited in oil-contaminated soils and that the suspected causes are disrupted soil moisture regimes and possibly ion toxicity. Attempts at reclamation of petroluem-contamined soils in temperate regions have been generally successful with cultivation (mixing for oxidizing conditions), fertilization, and liming over a period of 3 to 4 years. It is also recognized that periods of enhanced growth can occur at the latter stages of oil degradation. This is generally attributed to an increase in nitrogen and the better water retention by the soil.[96]

When a spill flows directly into a river, downstream communities using the river for drinking water are affected. Most commonly, they simply close their intakes for a period of about a day, and operate off standby capacity. Communities further downstream will receive the pollutant in smaller concentrations over a longer time period, making it more difficult for them to avoid contamination of their drinking waters.

A spill may also contact a community's water supply by more indirect means. For example, some of the oil may seep down through the soil and into the groundwater, or be gradually carried to the main water supply by a small stream.

In such cases, the contamination is expected to be minor, with odors or oil-sheens rather than immediate poisoning. These effects are expected to last up to a year or two in the case of groundwater contamination, giving rise to possible long-term toxic effects.

A major danger of terrestrial spills is that they can occur near lakes, rivers, streams, marshes, and other aquatic systems. When this occurs, locally severe impacts can adversely affect most elements of the aquatic ecosystem, including fishes, benthic fauna, and micro-organisms. Small mammals such as muskrats, beaver, river otters, etc., living near the affected waters are also likely to be impacted. Oil contamination of small mammals can take the form of insulation losses by coating or even toxic responses due to ingestion. Because the area affected by such spills is almost always limited and the sizes of the spills are generally small, food web effects of terrestrial oil spills are extremely difficult to trace.

# FOOTNOTES

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[77] Boesch, Hershner, Milgram, Oil Spills and the Marine Environment, p. 21.

[78] Boesch, Hershner, Milgram, Oil Spills and the Marine Environment, p. 25.

[79] Boesch, Hershner, Milgram, Oil Spills and the Marine Environment, p. 25.

[80] Nelson-Smith, Oil Pollution and Marine Ecology, p. 174.

[81] Nelson-Smith, Oil Pollution and Marine Ecology, p. 174, from G.B. Crapp, "Monitoring the Rocky Shore," in The Ecological Effects of Oil Pollution on Littoral Communities (London: Institute of Petroleum, 1971).

## FOOTNOTES (CONT.)

[82] Boesch, Hershner, Milgram, Oil Spills and the Marine Environment, pp. 21-22.

[83] Boesch, Hershner, Milgram, Oil Spills and the Marine Environment, p. 23, from J.M. Baker, "Refinery Effluent," in The Ecological Effects of Oil Pollution in Littoral Communities (London: Institute of Petroleum, 1971), pp. 33-43; J.M. Baker, "Successive Spills," in The Ecological Effects of Oil Pollution in Littoral Communities, pp. 21-32.

[84] Nelson-Smith, Oil Pollution and Marine Ecology, p. 155.

[85] Nelson-Smith, Oil Pollution and Marine Ecology, p. 212.

[86] Boesch, Hershner, Milgram, Oil Spills and the Marine Environment, p. 18, from H.L. Sanders et al., The West Falmouth Oil Spill, I - Biology, Technical Report of the Woods Hole Oceanographic Institution, No. 72-20.

[87] Boesch, Hershner, Milgram, Oil Spills and the Marine Environment, p. 18, from M.L.H. Thomas, "Effects of Bunker C Oil on Intertidal and Lagoonal Biota in Chedabucto Bay, Nova Scotia, Journal of the Fisheries Research Bd. Canada 30 (1973): 83-90.

[88] Nelson-Smith, Oil Pollution and Marine Ecology, pp. 84-85.

[89] D.E. Kash et al., Energy Under the Oceans (Norman, Okla.: University of Oklahoma Press, 1973), from W.G. Evans, "Thalassotrechus barbarae (Horn) and the Santa Barbara Oil Spill," The Pan-Pacific Entimologist 46 (October 1970): 233.

[90] Nelson-Smith, Oil Pollution and Marine Ecology, pp. 85-86.

[91] Boesch, Hershner, Milgram, Oil Spills and the Marine Environment, p. 18, from Thomas, "Effects of Bunker C Oil."

[92] Nelson-Smith, Oil Pollution and Marine Ecology, p. 85, from C.H. Roberts, "The Effect of Oil Pollution Upon Certain Forms of Aquatic Life," J. Cons. perm. intern. Explor. mer. 1 (1926): 245-275.

## FOOTNOTES (CONT.)

[93] U.S. Department of the Interior, Bureau of Mines, *Crude Petroleum, Petroleum Products and Natural Gas*, *Annual Petroleum Statement*, Table 2.

[94] Department of Transportation, Office of Hazardous Materials, *Summary of Liquid Pipeline Accidents Reported on DOT Form 7000-1*.

[95] Bureau of Mines, *Crude Petroleum, Petroleum Products and Natural Gas*, Table 5.

[96] F.J. Deneke et al., *Biological Aspects of Terrestrial Oil Spills*, U.S. Army Corps of Engineers, Research Report 346, 1975.

# APPENDIX E

## STRIPPER WELL PRODUCTION

# APPENDIX E

## STRIPPER WELL PRODUCTION

The Energy Conservation and Production Act exempted stripper well crude oil from price regulations as of September 1, 1976. As a result, stripper output will be unaffected by Stage II or III price incentives. However, stripper oil is included in the computation of the composite domestic oil price. Hence, the quantity of stripper production will, by its influence on the composite price, affect response to the price incentives.

### A. Onshore Leases Producing 10 Barrels per Day or Less per Well

The purpose of this section is to describe the method used to forecast stripper production in 1979. Data on the number and output of wells averaging 10 barrels per day or less oil production are collected and published annually by the National Stripper Well Association. The latest detailed data published[1] show that 1974 stripper well production was 1.129 million barrels per day. Imcomplete data for 1975[2] indicate essentially no change from 1974.

A published study was used for estimating 1979 production from stripper wells.[3] In this study, Professor Pederson related price/cost ratios to stripper production. Average stripper well cash operating costs for the tri-state area of Texas, Oklahoma and Kansas and the GNP deflator for private fixed investments were shown to be:

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[1] Oil and Gas Journal (November 3, 1975): 23

[2] Oil and Gas Journal (May 17, 1976): 80

[3] John A. Pederson, Colorado School of Mines, "Cost-Price Study of Producing Stripper Wells," Oil and Gas Journal (January 7, 1974): 71 ff.

|  | Operating Cost, Cents Per Barrel | Deflator | Ratio |
|---|---|---|---|
| 1970 | 209 | 132.5 | 1.58 |
| 1971 | 210 | 139.3 | 1.51 |
| 1972 | 229 | 144.8 | 1.58 |
| Average |  |  | 1.56 |

Since no cost data were shown for later years, an average cost/deflator ratio of 1.56 will be used to estimate 1976 costs. The 1976 deflator can be forecast from the known 1974 value of 165.3[4] and the GNP deflator forecasts utilized for oil price calculations:[5]

$$165.3 \times 1.051 \times 1.054 = 183.0$$

So, stripper well operating cost in 1976 is estimated to be:

$$183 \times 1.56 = 285 \text{ cents per barrel}$$

Average stripper oil price in mid-1976 was about $11.50 per barrel. Allowing this oil to be sold at free market price less entitlements adjustment would increase its wellhead value to about $12.00. So the average price/cost ratio in 1976 is:

$$1{,}200/285 = 4.21$$

By interpolation in the upper part of Table E-1, it is seen that a 4.2 price/cost ratio will increase tri-state area cumulative production by about 280 million barrels during the 1973-1980 period. From the relationship between Table E-1 and Figure E-1, the 1979 portion of the 7-year tri-state production is:

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[4] U.S. Bureau of the Census, Statistical Abstract of the United States: 1975, p. 416.

[5] Data Resources, Inc., "Review for FEA," (August 1976).

## TABLE E-1

## POTENTIAL ADDITIONAL CRUDE OIL

(1973-1980)

### Case I (10 Percent Decline)

| Avg. Price/ Cost Ratio | Production bbl |
|---|---|
| 3.72 | 145,000,000 |
| 4.11 | 259,000,000 |
| 4.54 | 346,000,000 |
| 5.02 | 412,000,000 |
| 5.55 | 459,000,000 |
| 6.13 | 491,000,000 |

### Case II (5 Percent Decline)

| Avg. Price/ Cost Ratio | Production bbl |
|---|---|
| 3.57 | 148,000,000 |
| 3.76 | 271,000,000 |
| 3.95 | 370,000,000 |
| 4.15 | 449,000,000 |
| 4.36 | 508,000,000 |
| 4.59 | 550,000,000 |
| 4.82 | 576,000,000 |
| 5.07 | 588,000,000 |

Source: The Oil and Gas Journal (January 7, 1974): 74.

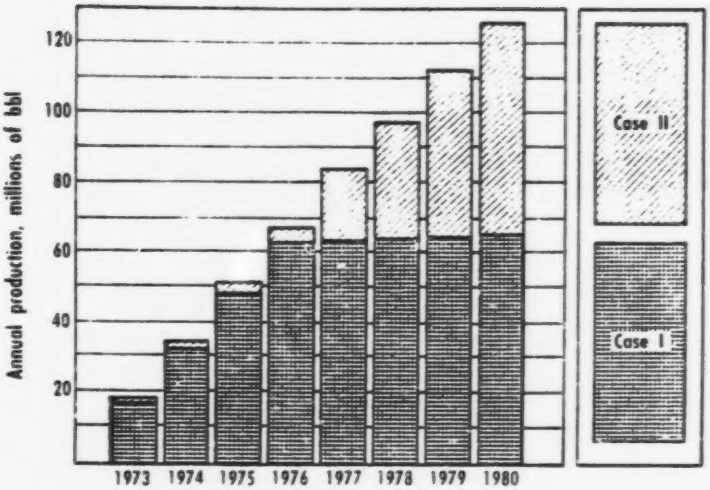

Figure E-1. Projected Increase. (*The Oil and Gas Journal* (January 7, 1974): 74.)

$$\frac{65 \text{ (Figure E-1)}}{412 \text{ (Table E-1)}} \times 280 = 44 \text{ million barrels}$$

Since the tri-state area produced 60 percent of U.S. stripper oil in 1975,[6] additional stripper production in 1979 in the total U.S. attributable to the post-1973 price/cost ratio is estimated to be:

$$\frac{44}{0.6} = 73 \text{ million barrels per year or 200 thousand barrels per day}$$

Had the pre-1974 price/cost ratio continued through 1979, stripper production would have been expected to continue to decline at the historical net rate of 4.1 percent per year observed during the period 1967-1974.[7] Applying this decline rate to 1974 U.S. stripper production (1,129 thousand barrels per day) gives a pre-price-increase forecast of 915 thousand barrels per day. Adding the "Pederson price/cost increment" yields a 1979 forecast for output from U.S. stripper wells of (915 + 200 =) 1,115 thousand barrels per day.

## B. Deep Onshore Wells Producing Twenty Barrels per Day or Less

The purpose of this Section is to document the conclusion that negligible additional production would be achieved by reclassifying onshore wells deeper than 6,000 feet from lower tier to stripper price classification.

Two approaches were taken to this problem. The first argument proceeds as follows. In the preceding section of this appendix it was shown that the current price/cost ratio for stripper wells is about four. As an outside case, assume that this ratio for deep wells is only three. With stripper oil selling at $12 per barrel (or more), a 10 barrel per day deep well will yield a cash income of roughly $120,000[8] over the next 15 years (by which time production will have declined to roughly 2 barrels per day). During the 3-year period between now and mid-1979 when price controls cease, a 20 barrel per day deep well should about break even.[9] Rather than shut down, a producer would probably continue operations during the next 3 years in order to be able to realize the substantial cash flow that begins in mid-1979.

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[6] Oil and Gas Journal (November 3, 1975): 73.

[7] American Petroleum Institute, Basic Petroleum Data Book, Section IV, Table 4.

The second argument is based on industry wells/depth data collected for 1971. The data are as follows:

| | Number of Wells With Indicated Production Rate | | |
|---|---|---|---|
| Production Rate Barrels Per Day | 4,000-6,000 Feet Deep | 6,000-8,000 Feet Deep | More Than 8,000 Feet Deep |
| Between 20 and 36 | 11,960 | 7,090 | 6,780 |
| Between 12 and 20 | 12,280 | 6,370 | 6,390 |
| Ratio 12-20/20-36 | 1.03 | 0.90 | 0.94 |

If 12-20 barrel per day wells were less economical at greater depths, one would expect the ratio of 12-20 wells to 20-36 wells to decline steadily with increasing depth. The fact that it does not supports the assumption that reclassification of deep onshore wells producing 10-20 barrels per day to stripper would have a negligible effect on production.

## C. Offshore Wells Producing Forty Barrels per Day or Less

Offshore wells are much more expensive to operate than are onshore wells. So the analysis of the preceding section cannot be extrapolated to offshore wells. Low-production rate offshore wells can occur in three Petroleum Supply Regions: 1 (Cook Inlet),

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[8] $12 per barrel x 2/3 gross profit x (1 - 0.5 income tax rate) x 10 barrels per day x 365 days per year = $14,600 in the first year; $14,600 x .9 - $13,140 in the second year, etc.

[9] From the previous footnote, operating cost is about $4 per barrel (1/3 of $12). Current lower tier price is about $5 per barrel.

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2A (off the Pacific Cost) and 6A (off the Gulf Coast). Since any effects in Regions 1 and 2A of changed stripper rules would be small compared to the effects in Region 6A, the analysis was restricted to 6A.

The analysis is based on two data sources:

1. A summary (performed on August 1, 1976) of U.S. Geological Survey data on all wells in the outer continental shelf of the Gulf, and
2. Lewin and Associates, Inc., Economic Limits of OCS Production Wells, FEA Contract No. CO-03-50222-000, April 1976.

The latter work has been criticized as being simplistic. However, its overall conclusions appear reasonable and adequate for the screening analysis performed here. Also, it is the only known immediately available estimate.

The pertinent parts of the Geological Survey data are reproduced here:

| MPR (Maximum Production Rate Per Well) in 1975 Barrels Per Day | Cumulative MPR Barrels Per Day |
|---|---|
| 0-9 | 91 |
| 10-19 | 763 |
| 20-29 | 2,511 |
| 30-39 | 5,679 |
| 40-49 | 9,248 |
| 50-59 | 13,965 |
| 60-69 | 20,265 |
| 70-79 | 27,930 |
| 80-89 | 35,151 |
| 90-99 | 42,870 |
| 100-129 | 68,122 |
| 130-159 | 99,946 |

According to the Lewin Report, the economic production limit at a "real" (1975) price of $5.25 per barrel is 45 barrels per day per well; and at $11.28 per barrel, the limit is 20 barrels per day per well. Ratioing (by gross revenue) to the free market price of $13 per barrel, the economic limit would be 17 barrels per day per well. Therefore, releasing wells that produce up to 40 barrels per day to the free market price would have the effect of maintaining production from wells in the 17-40 barrel per day range. These wells would shut down at lower tier prices. At the average lower tier real price for Stage II options of $4.50 per barrel, the economic limit would be 52 barrels per day. It is assumed that these wells (40-52 barrels per day) will continue production to obtain the substantial price increases when the wells deplete to 40 barrels per day. When a lower tier well reaches its economic breakeven point of 52 barrels per day it would normally shut down. But, if the producer foresees a period of high profitability beginning two or three years later (when output has declined to 40 barrels per day), he will keep his well on stream despite the period of interim losses. The Geological Survey data are used to predict production rate for these wells.

Two factors must be considered to translate 1979 production rate to 1975 MPR. First, the ratio of production to MPR is assumed to be 0.7. Second, production from offshore wells depletes at a rate of about 15 percent per year.[10] Hence, the 1975 MPR equivalent to 1979 production of 17 barrels per day is:

$$\frac{17}{(0.85)^4 \times 0.7} = 47 \text{ barrels per day}$$

Also, the 1975 MPR equivalent to a 1979 production of 52 barrels per day is 143 barrels per day. From the table previously shown, the cumulative MPR between 47 and 143 barrels per day is (78,000 - 9,000 =) 69,000 barrels per day. The equivalent 1979 production is (69,000 x 0.7 x $0.85^4$ =) 25,000 barrels per day. Therefore, it was assumed that reclassification of offshore lower tier wells to stripper would increase 1979 U.S. production by about 25,000 barrels per day.

It must be noted that, if the Lewin estimates were accurate, there would have been no wells in 1975 producing less than 52 barrels per day (MPR of 74). In fact, about (24,000 x 0.7 =) 17,000 barrels per day were produced from wells smaller than this supposedly critical size. By 1979, these wells will be producing something less than (17,000 x $0.85^4$ =) 9,000 barrels per day. Consequently it could be argued that the effect of reclassification is more likely to be less than 20,000 barrels per day than the 25,000 barrels per day estimated above.

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[10] Vintaged Production tables for Region 6A from PIES run OBAU 1212. A sample of these tables is shown and discussed in Appendix F.

# APPENDIX F

## DERIVATION OF SUPPLY CURVES

## APPENDIX F

## DERIVATION OF SUPPLY CURVES

Estimates of the effect of price on production were derived from "supply curves" for each type of production. The derivation of these curves for each region is described herein for primary plus secondary production and for tertiary production.

### A. Primary Plus Secondary Production

Price/volume data for primary and secondary production from existing (drilled before 1975) and new (drilled after 1974) wells in each producing region were developed for use in the Project Independence Evaluation System (PIES). Each of these data is a point on the supply curve for a given region. The supply curves for Region 8-9-10 will be derived to show the procedure.

The PIES price/volume points are shown in computer output tables (Tables F-1 through F-4) entitled "Vintaged Production from Region 810L, Run OBAU 1212 - 11/15/75," Type ID 4 (existing primary), 5 (existing secondary), 1 (new primary) and 2 (new secondary). These tables are reproduced on the following pages. From the column headed "1979," the following supply curve points can be picked:

| | | Production In 1979, Thousand Barrels Per Day | |
|---|---|---|---|
| ble I.D. | Price, $(1975) Per Barrel | Increment | Cumulative |
| 5 | 0.56 | 54 | 34 |
| 5 | 0.60 | 15 | 49 |
| 4 | 3.53 | 114 | 163 |
| [illegible] | 8.18 | 12 | 175 |
| 1 | 8.25 | 12 | 187 |
| 1 | 8.30 | 13 | 200 |
| 1 | 8.58 | 16 | 216 |

Since the lowest price considered in this work is $4.19 (1975 dollars) per barrel (in Case IIC), at least 163,000 barrels per day of production will be achieved in every case and only the higher-priced portion of the curve need be considered when determining the effects of price changes. This

## TABLE F-1

## VINTAGED PRODUCTION FROM REGION NO. 810L - TYPE ID: 1

(RUN: OBAU1212 11/15/75)

| YEAR PROVED | $ / B | YEAR PRODUCED: MB/D | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | 1975 | 1976 | 1977 | 1978 | 1979 | 1980 | 1981 | 1982 | 1983 | 1984 | 1985 |
| 1975 | 8.18 | 0 | 18 | 15 | 13 | 12 | 10 | 9 | 8 | 7 | 6 | 5 |
| 1976 | 8.25 | 0 | 0 | 16 | 14 | 12 | 11 | 9 | 8 | 7 | 6 | 5 |
| 1977 | 8.30 | 0 | 0 | 0 | 15 | 13 | 11 | 10 | 9 | 8 | 7 | 6 |
| 1978 | 8.58 | 0 | 0 | 0 | 0 | 16 | 14 | 12 | 11 | 9 | 8 | 7 |
| 1979 | 8.80 | 0 | 0 | 0 | 0 | 0 | 19 | 16 | 14 | 12 | 11 | 9 |
| 1980 | 9.64 | 0 | 0 | 0 | 0 | 0 | 0 | 21 | 18 | 16 | 14 | 12 |
| 1981 | 9.91 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 23 | 20 | 17 | 15 |
| 1982 | 10.20 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 24 | 21 | 19 |
| 1983 | 10.49 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 27 | 23 |
| 1984 | 10.84 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 29 |
| 1985 | 11.53 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

## TABLE F-2

## VINTAGED PRODUCTION FROM REGION NO. 810L - TYPE ID: 2

(RUN: OBAU1212 - 11/15/75)

| YEAR PROVED | $ / B | YEAR PRODUCED: MB/D<br>1975 | 1976 | 1977 | 1978 | 1979 | 1980 | 1981 | 1982 | 1983 | 1984 | 1985 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1975 | 0.0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 1976 | 0.0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 1977 | 0.0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 1978 | 0.0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 1979 | 0.0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 1980 | 8.18 | 0 | 0 | 0 | 0 | 0 | 0 | 5 | 5 | 4 | 4 | 3 |
| 1981 | 8.25 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 5 | 4 | 4 | 3 |
| 1982 | 8.30 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 5 | 4 | 4 |
| 1983 | 8.58 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 5 | 4 |
| 1984 | 8.80 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 6 |
| 1985 | 9.64 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

# TABLE F-3

## VINTAGED PRODUCTION FROM REGION NO. 810L - TYPE ID: 4

(RUN: OBAU1212 - 11/15/75)

| YEAR PROVED | $ / B | | | | | YEAR PRODUCED: MB/D | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | 1975 | 1976 | 1977 | 1978 | 1979 | 1980 | 1981 | 1982 | 1983 | 1984 | 1985 |
| 1975 | 3.53 | 198 | 172 | 150 | 131 | 114 | 99 | 86 | 75 | 65 | 57 | 49 |
| 1976 | 0.0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 1977 | 0.0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 1978 | 0.0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 1979 | 0.0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 1980 | 0.0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 1981 | 0.0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 1982 | 0.0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 1983 | 0.0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 1984 | 0.0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 1985 | 0.0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

## TABLE F-4

## VINTAGED PRODUCTION FROM REGION NO. 810L - TYPE ID: 5

(RUN: OBAU1212 - 11/15/75)

| YEAR PROVED | $ / B | YEAR PRODUCED: MB/D 1975 | 1976 | 1977 | 1978 | 1979 | 1980 | 1981 | 1982 | 1983 | 1984 | 1985 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1975 | 0.56 | 0 | 15 | 13 | 11 | 10 | 9 | 7 | 6 | 6 | 5 | 4 |
| 1976 | 0.56 | 0 | 0 | 15 | 13 | 11 | 10 | 9 | 7 | 6 | 6 | 5 |
| 1977 | 0.56 | 0 | 0 | 0 | 15 | 13 | 11 | 10 | 9 | 7 | 6 | 6 |
| 1978 | 0.60 | 0 | 0 | 0 | 0 | 15 | 13 | 11 | 10 | 9 | 7 | 6 |
| 1979 | 0.61 | 0 | 0 | 0 | 0 | 0 | 15 | 13 | 11 | 10 | 9 | 7 |
| 1980 | 1.61 | 0 | 0 | 0 | 0 | 0 | 0 | 14 | 12 | 10 | 9 | 8 |
| 1981 | 1.62 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 14 | 12 | 10 | 9 |
| 1982 | 1.62 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 14 | 12 | 10 |
| 1983 | 1.62 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 14 | 12 |
| 1984 | 1.63 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 14 |
| 1985 | 2.65 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

higher-priced portion of the supply curve is plotted in Figure III-2 along with the high-priced segments of the primary plus secondary supply curves for the other regions.

## B. Tertiary Production

Supply curves for tertiary production (alternatively known as "enhanced oil recovery," or "EOR") were derived from "The Potential and Economics of Enhanced Oil Recovery," Lewin and Associates, Inc., FEA Contract CO-03-50222-000, April 1976.

On pages 4-14 to 4-19 of the Lewin report, the following supply curve points are presented for 1979 EOR in the three states of Texas, California and Louisiana:

| Price $(1975) per Barrel | Federal Non-Price Input | Production, Thousand Barrels per Day |
|---|---|---|
| 5.25 | Moderate | 302 |
| 11.28 | Moderate | 406 |
| 11.28 | High | 526 |

The first two points were assumed to describe the underlying price/volume relationship for EOR. The last point was utilized only in the evaluation of pricing stage IIIB (total production from tertiary projects gets free market price).

No disaggregations of states, or of methods by state, are shown for 1979 in the report (nor, according to the Project Director, are they available in Lewin's files). So it was necessary to develop reasonable estimates from other data in the Lewin report. The derivation of the estimates for Region 2 for an $11.28 per barrel real price will be developed to show the procedure used.

All EOR production in Region 2 will occur in California. The production forecast by EOR method in 1979 is not known, but 1980 production is shown on Lewin page 3-13 (for an $11.28 price and high Federal input). Lacking other data, the relative proportions in this table were used to disaggregate by method in 1979 total EOR production.

| | Production, Thousand Barrels Per Day | |
|---|---|---|
| EOR Method | 1980 (Lewin 3-13) | $\times\frac{406}{700} = 1979 \text{ @ } \$11.28$ |
| Steam drive | 300 | 174 |
| In-situ combustion | 100 | 58 |
| Miscible flood | 300 | 174 |
| | 700 | 406 |

The Lewin tables cited above include an estimate of 174 thousand barrels per day EOR production in California/Texas/ Louisiana in 1975. But a detailed survey by the *Oil and Gas Journal*[1] indicates that actual production was about 260 thousand barrels per day. It was decided to adjust the Lewin 1979 supply curve points to account for this difference. Since the difference is due to a speeding up of project development, rather than an increase in reserves, the difference should become smaller over time. A decay rate of 10 percent per year was estimated. Thus, the 1979 Lewin quantities were each increased by [(260-174) x $0.9^4$ = ] 56 thousand barrels per day to:

| Price | Input | Production |
|---|---|---|
| 5.25 | Moderate | 360 |
| 11.28 | Moderate | 460 |
| 11.28 | High | 580 |

Disaggregating the 56 thousand barrel per day difference in proportion to known production for each method in 1974 yields the following estimate of 1979 EOR production:

---

[1] *Oil and Gas Journal* (April 5, 1976), pp. 107ff.

| Method | Production, Thousand Barrels per Day<br>Lewin | <br>Adjustment | <br>Revised |
|---|---|---|---|
| Steam | 174 | 36 | 210 |
| In-situ | 58 | 2 | 60 |
| Miscible | 174 | 16 | 190 |
|  | 406 | 54 | 460 |

Pages 4-4 to 4-6 in the Lewin report show the relationship between EOR reserves and price:

Cumulative Reserves at
$11.28 per Barrel Real Price
(Billion Barrels)

| EOR Method | California | Texas | Louisiana | Total |
|---|---|---|---|---|
| Steam | 12.2 | 0.3 | - | 12.5 |
| In-situ | 0.8 | - | 0.6 | 1.4 |
| Miscible | 1.2 | 8.9 | 0.4 | 10.5 |

Allocating the known total production by each method to Region 2 (California) on the basis of that state's fraction of total reserves and rounding:

1979 Production at $11.28
per Barrel Real Price
and Moderate Federal Input
(Thousand Barrels per Day)

| EOR Method | Region 2 | Texas and Louisiana | Total |
|---|---|---|---|
| Steam | 210 | - | 210 |
| In-situ | 30 | 30 | 60 |
| Miscible | 20 | 170 | 190 |
| Total | 260 | 200 | 460 |

The same method was used to derive the region/method production points for a real price of $5.25 per barrel.

The real price of lower tier production in the Base Case and IIC cases is $4.19 per barrel. So $4.00 per barrel region/production points were also required for the analysis. Exhibits 4-3 and 4-3 in the Lewin study show that no tertiary production will occur in Texas or Louisiana at a $4.00 real price (except for that which was in operation in 1974). But Exhibit 4-1 shows that California (Region 2) steam-enhanced reserves at $4.00 per barrel are about 80 percent of reserves at $5.25 per barrel. So, Region 2 steam-enhanced production in 1979 at $4.00 per barrel was estimated to be 160 thousand barrels per day, which is 80 percent of the $5.25 per barrel production estimate.

# APPENDIX G

## OPTION-INDEPENDENT PRODUCTION AND LOWER TIER PRODUCTION

# APPENDIX G

## OPTION-INDEPENDENT PRODUCTION AND LOWER TIER PRODUCTION

Appendix F supply curves were developed for those parts of 1979 production that will be affected by price. It is the purpose of this appendix to explain the source of the volume estimates for the parts of 1979 production that will not be affected by the pricing options studied herein.

The lowest price studied -- in "real" 1975 dollars -- is $4.19 per barrel. This price occurs when lower tier prices are held at constant nominal values, as in the Base Case and all stage IIC cases. The lowest upper tier real price is $7.25 per barrel. This occurs uniquely in the Base Case. So, any production costing less than these prices will be unaffected by pricing options. (Some Region 2 tertiary production costs less than $4.19 per barrel. For convenience, this production was handled along with the rest of tertiary production as described in Appendix F).

### A. Total Option-Independent Production Volumes

There are four parts of 1979 production that will be the same for all pricing options studied herein:

1. Wells classified as strippers under the current definition. These wells face the same price (free market) in all options, including the Base Case.

2. Non-stripper primary and secondary production costing less than $4.19 (real price) per barrel. This includes all production shown in PIES Vintaged Production tables for pre-1976 wells (Table ID 4 and 5).

3. Primary and secondary production from post-1975 wells (all upper tier) costing less than $7.25 per barrel. These volumes appear in PIES tables ID 1 and 2 for Regions 2, 6A, 11 and 11A, along with higher cost production.

4. North Slope production. This was assumed to be independent of price over the range studied -- $7.25 in the Base Case and $10.50 in all other cases.

## TABLE G-1

## OPTION-INDEPENDENT 1979 PRODUCTION VOLUMES OTHER PRIMARY AND SECONDARY PRODUCTION

(Thousand Barrels Per Day)

| REGION | STRIPPER PRODUCTION | PRE '76 | POST '75 BELOW $7.25 | NORTH SLOPE | TOTAL |
|---|---|---|---|---|---|
| No. Sl. | | | | 1,420 | 1,420 |
| 1 | | 120 | | | 120 |
| 2 | 210 | 451 | 200 | | 861 |
| 2A | | 94 | | | 94 |
| 3 | 7 | 173 | | | 180 |
| 4 | 13 | 461 | | | 474 |
| 5 | 240 | 1,411 | | | 1,651 |
| 6 | 170 | 2,452 | | | 2,622 |
| 6A | | 595 | 756 | | 1,351 |
| 7 | 325 | 191 | | | 516 |
| 8-9-10 | 150 | 13 | | | 163 |
| 11 | | 59 | 43 | | 102 |
| 11A | | | 50 | | 50 |
| TOTAL | 1,115 | 6,020 | 1,049 | 1,420 | 9,604 |

In Case IIIC, stripper production in Region 6A becomes 25,000 barrels per day, as developed in Appendix E. This extra stripper volume was handled explicitly in the computation.

### B. Lower Tier Primary and Secondary Production Volumes

In order to compute the composite price of U.S. production, it is necessary to know the volumes and prices of both upper and lower tier production. Lower tier volumes are derived in this section. Upper tier volume in each case is derived by difference.[1]

---

[1] Upper tier = option-dependent production (Appendix F) plus option-independent production (A. above) minus (lower tier plus North Slope).

Official FEA lower tier production volumes for the total United States for the first half of 1976 were:

| | Lower Tier Production Million Barrels Per Day |
|---|---|
| February 1976 | 4.60 |
| March | 4.68 |
| April | 4.61 |
| May | 4.56 |
| June | 4.49 |

Since production was dropping at the rate of 0.06 million barrels per day each month, an estimated average value for 1976 of 4.46 million barrels per day is assumed.

Lower tier production is of two types -- tertiary, for which supply curves were developed in Appendix F, and primary and secondary. Since tertiary production is about 0.26 million barrels per day,[2] average 1976 lower tier primary and secondary production is (4.46 - 0.26 =) 4.20 million barrels per day.

Production classified as lower tier is expected to decline at a rate of about 10 percent per year. This decline rate estimate is based on two considerations:

1. In the information accompanying the FEA promulgation of new ceiling prices,[3] an "old" crude oil decline rate of 8 percent per year was estimated.

2. The lower tier decline rate will be larger than the old oil decline rate because of routine redefinitions of production from lower to upper tier, and because of the incentive for lower tier wells with 10 to 25 barrels per day production to reduce output to below 10 barrels per day so as to qualify for stripper pricing.

---

[2] Oil and Gas Journal (April 5, 1976): 107ff.

[3] Federal Register (March 4, 1976): 9389.

Hence, 1979 lower tier primary plus secondary production will be $[4.20 \times (0.9)^3 =]$ 3.07 million barrels per day. Total lower tier production will be 3.07 plus tertiary production corresponding to the lower tier price in the specific case under study. (Because the composite price is computed on a national base, a national total lower tier volume is all that is needed. Regional lower tier volumes are irrelevant to the analysis.)

Lower tier primary plus secondary volume in 1979 is slightly different than 3.07 million barrels per day for pricing alternatives IIIB and IIID. In Case IIIB, the total production from tertiary projects, including co-produced primary and secondary oil, can be sold at the free market price. This co-produced oil would otherwise be lower tier. As described in Chapter III, a procedure was developed to estimate the volume of this bonus oil. The estimate is that 0.25 million barrels per day is shifted from lower to upper tier. So lower tier primary and secondary volume in Case IIIB is (3.07 - 0.25 =) 2.82 million barrels per day.

In Case IIID, the size of the gravity differential in California is reduced. It was estimated that this change would cause California production to be 0.02 million barrels per day greater than it would be if the current gravity differential remained in effect. This additional production will most likely be from old lower tier wells that continue in operation instead of shutting down. So lower tier volume in this case is (3.07 + 0.02 =) 3.09 million barrels per day.

# APPENDIX H

## IMPACT OF PRICE CONTROLS ON AVERAGE REVENUE OF TYPICAL PRODUCTION PROJECTS

# APPENDIX H

## IMPACT OF PRICE CONTROLS ON AVERAGE REVENUE OF TYPICAL PRODUCTION PROJECTS

The background for this analysis is given in the Introduction to Chapter III. The impact of 2 years of price controls will be computed for two example projects. A discount rate of 8 percent per year is assumed.[1]

Project 1. Twenty-year life with production declining at 10 percent per year.

Case A: Per-barrel revenue is $12.50 (free market real price) for all 20 years.

| Year | Production | Price | Continuous Discount Factor | Discounted Revenue |
|---|---|---|---|---|
| 1 | 100.0 | 12.50 | 0.9625 | 1,203 |
| 2 | 92.0 | -- | 0.8912 | 1,025 |
| 3 | 84.6 | -- | 0.8252 | 873 |
| 4 | 77.9 | -- | 0.7641 | 744 |
| : | : | --- | : | : |
| : | : | --- | : | : |
| 19 | 22.2 | --- | 0.2409 | 67 |
| 20 | 20.5 | --- | 0.2230 | 57 |
| | | | TOTAL | 7,792 |

Case B: Per-barrel revenue is $7.25 (Base Case upper tier price) for 2 years, and $12,50 thereafter.

| Year | Production | Price | Continuous Discount Factor | Discounted Revenue |
|---|---|---|---|---|
| 1 | 100.0 | 7.25 | 0.9625 | 698 |
| 2 | 92.0 | 7.25 | 0.8912 | 594 |
| 3 | 84.6 | 12.50 | 0.8252 | 873 |
| 4 | | | | |
| : | identical to Case A. | | | |
| : | | | | |
| | | | TOTAL | 6,856 |

---

[1] The value is appropriate for estimating the long-run cost of equity capital in the United States. See Fortune (December 1974): 100.

The "effective" price, i.e., the weighted average discounted price, in Case B can now be computed:

$$\$12.50 \times \frac{6,856}{7,792} = \$11.00 \text{ per barrel}$$

Project 2. Six-year life with constant production.

Case A: Per-barrel revenue is $12.50 for all 6 years.

| Year | Production | Price | Continuous Discount Factor | Discounted Revenue |
|---|---|---|---|---|
| 1 | 100 | 12.50 | 0.9625 | 1,203 |
| 2 | --- | --- | 0.8912 | 1,114 |
| 3 | --- | --- | 0.8252 | 1,032 |
| : | --- | --- | : | : |
| : | --- | --- | : | : |
| 6 | --- | --- | 0.6550 | 819 |
| | | | TOTAL | 6,007 |

Case B: Per-barrel revenue is $4.20 (lower tier real price) for 2 years, and $12.50 thereafter.

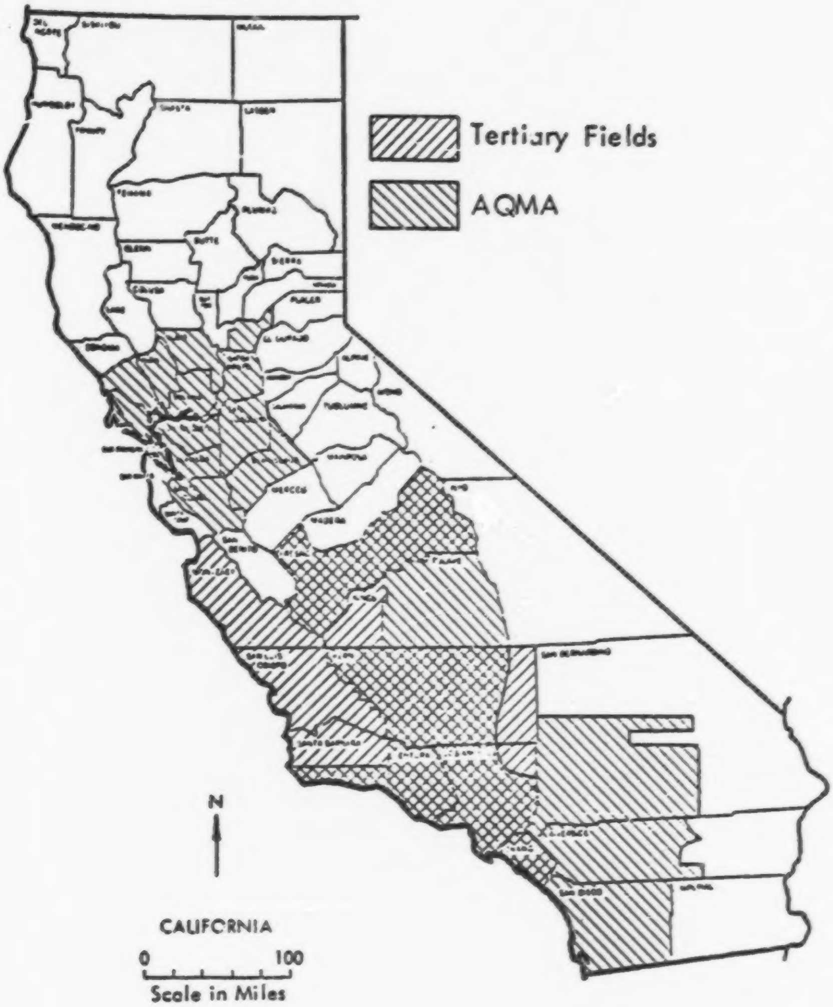
| Year | Production | Price | Continuous Discount Factor | Discounted Revenue |
|---|---|---|---|---|
| 1 | 100 | 4.20 | 0.9625 | 404 |
| 2 | --- | 4.20 | 0.8912 | 374 |
| 3 | --- | 12.50 | 0.8252 | 873 |
| : | | | | |
| : | | identical to Case A. | | |
| : | | | | |
| | | | TOTAL | 4,468 |

The "effective" price in Case B can now be computed:

$$\$12.50 \times \frac{4,468}{6,007} = \$9.30 \text{ per barrel.}$$

# APPENDIX I

## AIR QUALITY MAINTENANCE AREAS AND NONATTAINMENT AREAS IN RELATION TO OIL FIELDS IN SELECTED STATES


Tertiary Fields
AQMA
N
CALIFORNIA
0
100
Scale in Miles

| AQMA | AQMA Number | POLLUTANTS | | | | |
|---|---|---|---|---|---|---|
| | | PM | $SO_2$ | CO | $O_X$ | $NO_2$ |
| California | | | | | | |
| Fresno County | 031A | X | | | X | |
| Kern County | 031B | X | | X | X | |
| Sacramento Valley Area | 028A | | | X | X | |
| San Diego Air Basin | 019A | X | | X | X | |
| San Francisco Bay Area Ais Basin | 030A | X | X | | X | |
| San Joaquin & Stanislaus Counties | 031C | X | | | X | |
| South Coast Air Basin | 024A | X | X | X | X | X |
| Southeast Desert | 033A | | | | X | |
| Tulare County | 031D | X | | | | |

Figure I-1 - Locations of Existing Oil Fields and AQMA (California)

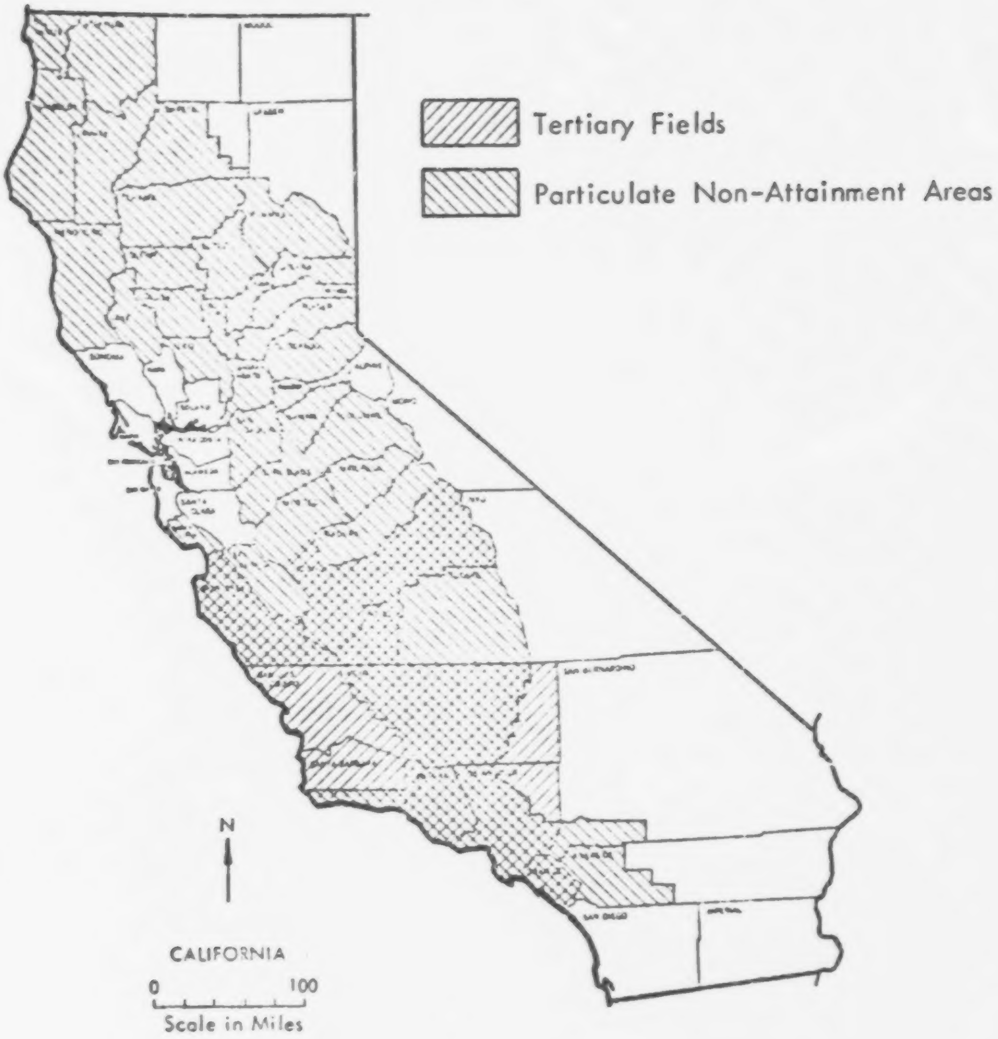

Tertiary Fields
Particulate Non-Attainment Areas
N
CALIFORNIA
0
100
Scale in Miles

Figure I-2 - Locations of Existing Oil Fields and Particulate Nonattainment Areas (California)

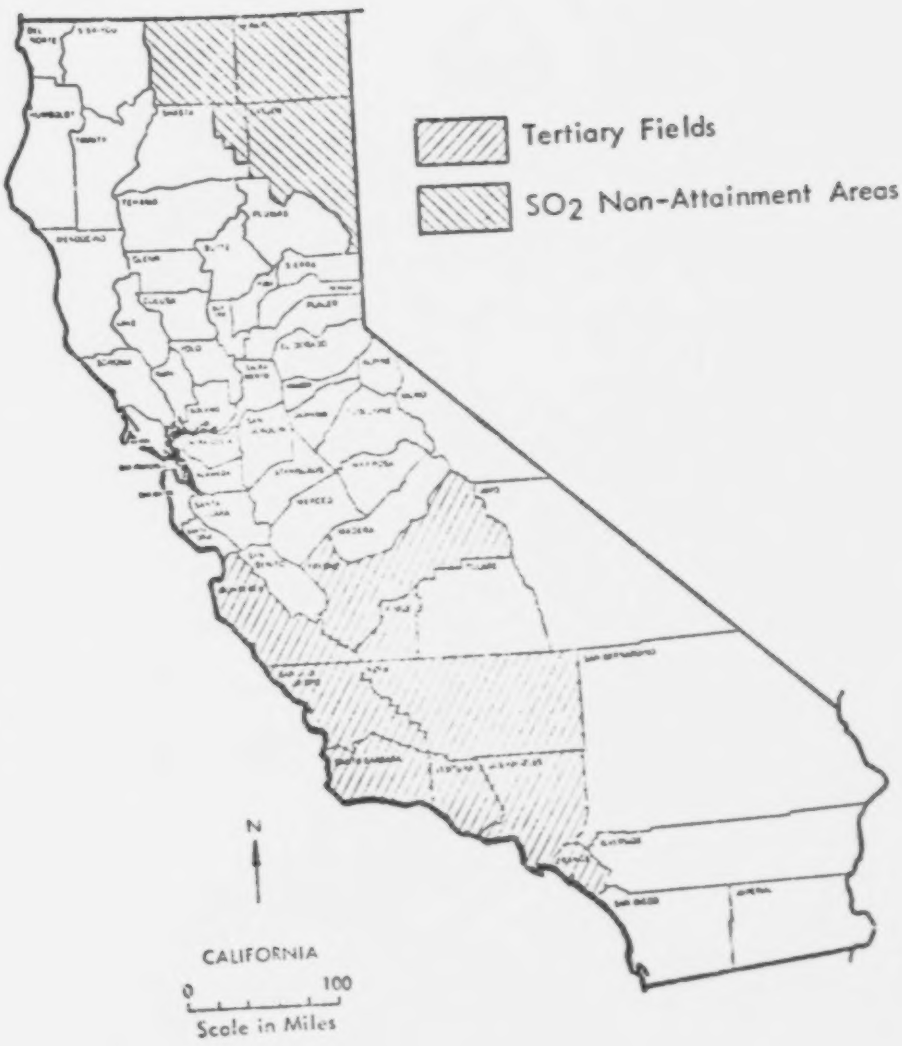

Tertiary Fields
SO2 Non-Attainment Areas
N
CALIFORNIA
0
100
Scale in Miles

Figure I-3 - Locations of Existing Oil Fields and $SO_2$ Non-attainment Areas (California)

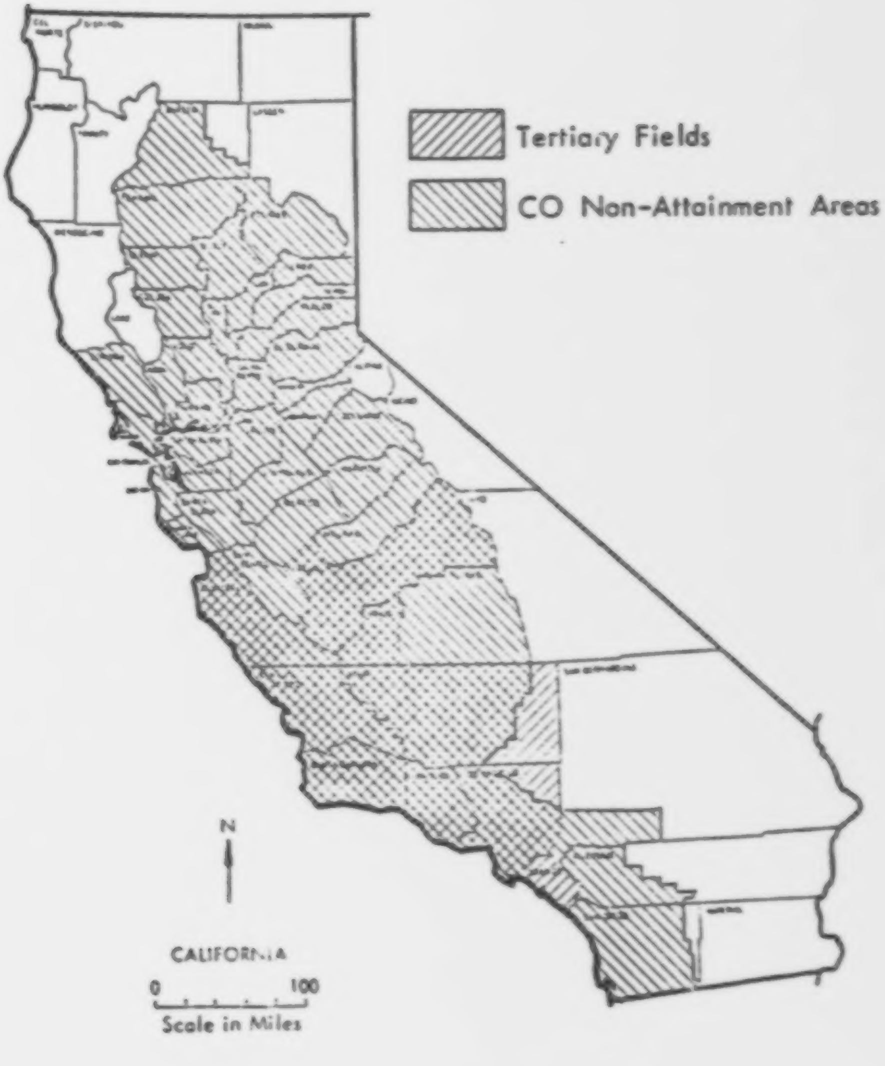

Tertiary Fields
CO Non-Attainment Areas
N
CALIFORNIA
0
100
Scale in Miles

Figure I-4 - Locations of Existing Oil Fields and CO Non-attainment Areas (California)

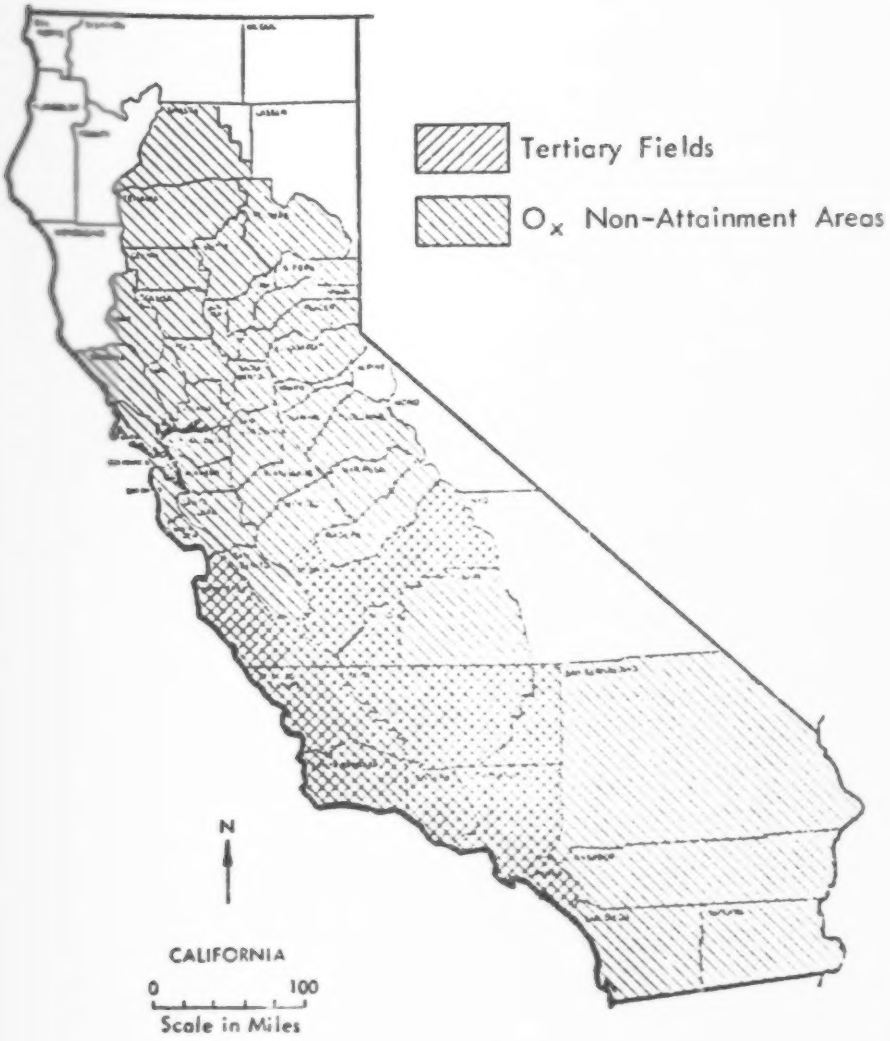

Tertiary Fields
$O_x$ Non-Attainment Areas
N
CALIFORNIA
0
100
Scale in Miles

Figure I-5 - Locations of Existing Oil Fields and $O_x$ Non-attainment Areas (California)

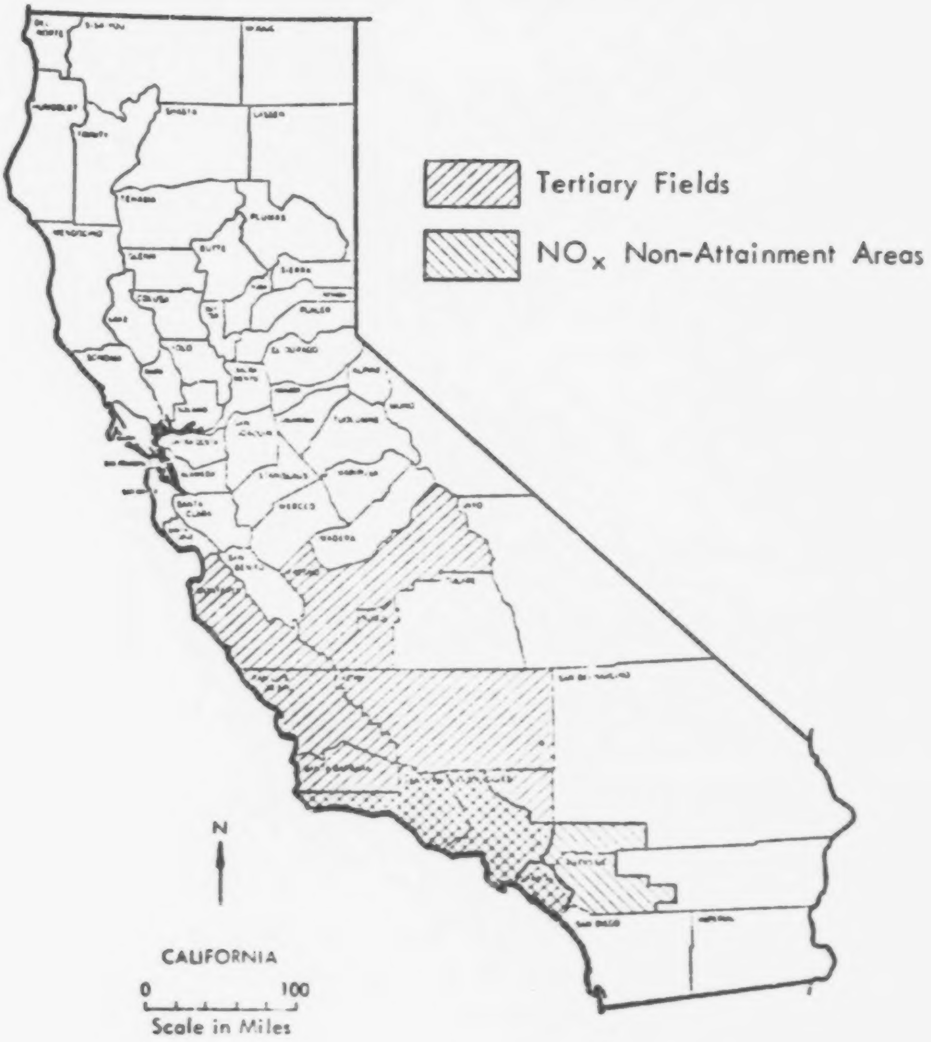
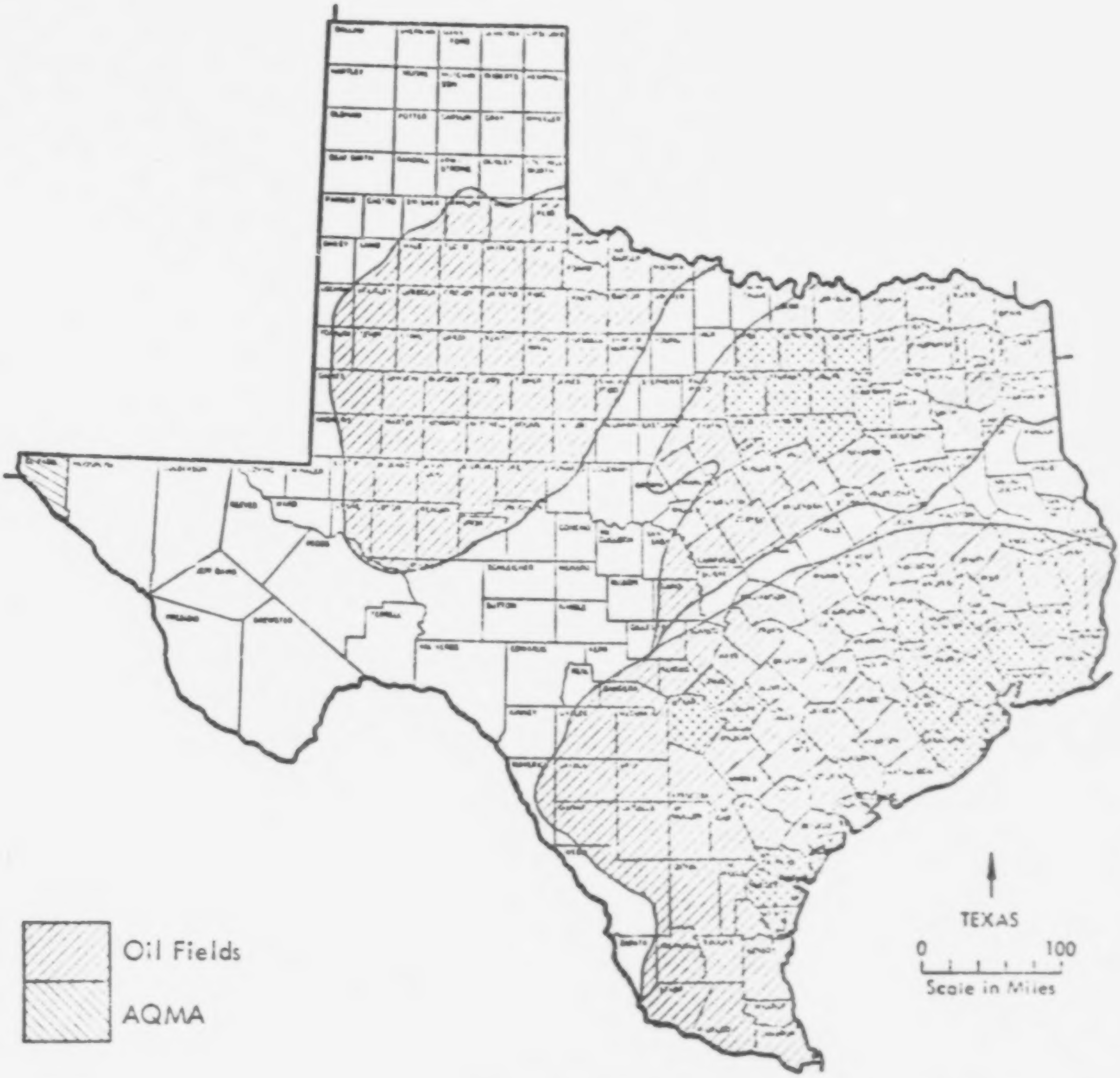

Tertiary Fields
NOx Non-Attainment Areas
N
CALIFORNIA
0
100
Scale in Miles

Figure I-6 - Locations of Existing Oil Fields and NO$_x$ Non-attainment Areas (California)


Oil Fields
AQMA
TEXAS
0
100
Scale in Miles

| AQMA | AQMA Number | POLLUTANTS | | | | |
|---|---|---|---|---|---|---|
| | | PM | $SO_2$ | CO | Ox | $NO_2$ |
| Texas | | | | | | |
| Beaumont | 106A | X | | | X | |
| Corpus Christi | 214A | X | | | | |
| Dallas-Ft. Worth | 215A | X | | | X | |
| El Paso | 153B | | | | X | |
| Galveston | 216A | X | X | | X | |
| Houston | 216B | X | | | X | |
| San Antonio | 217A | | | | X | |

Figure I-7 - Locations of Existing Oil Fields and AQMA (Texas)

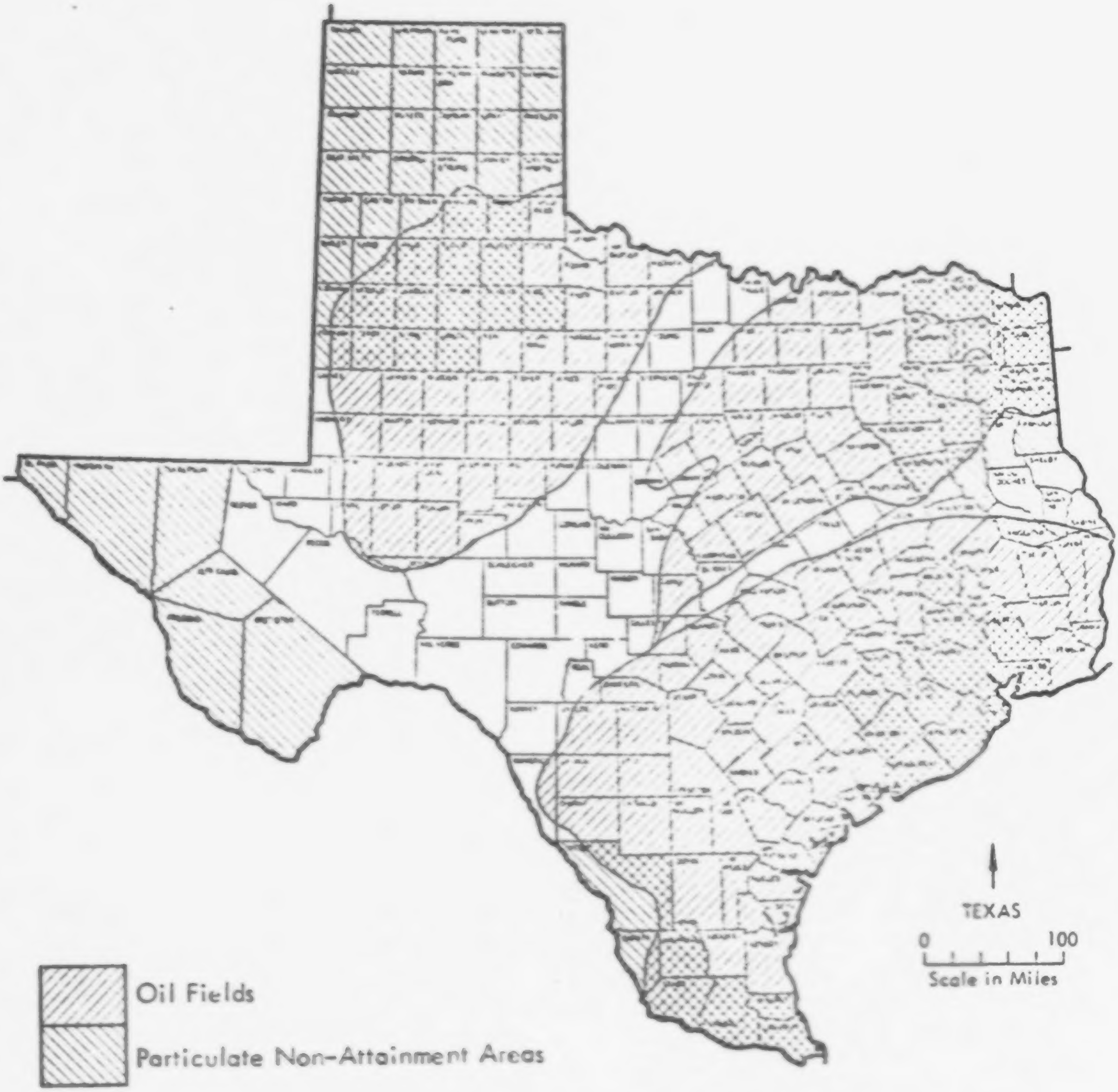

TEXAS
0
100
Scale in Miles
Oil Fields
Particulate Non-Attainment Areas

Figure I-8 - Locations of Existing Oil Fields and Particulate Nonattainment Areas (Texas)

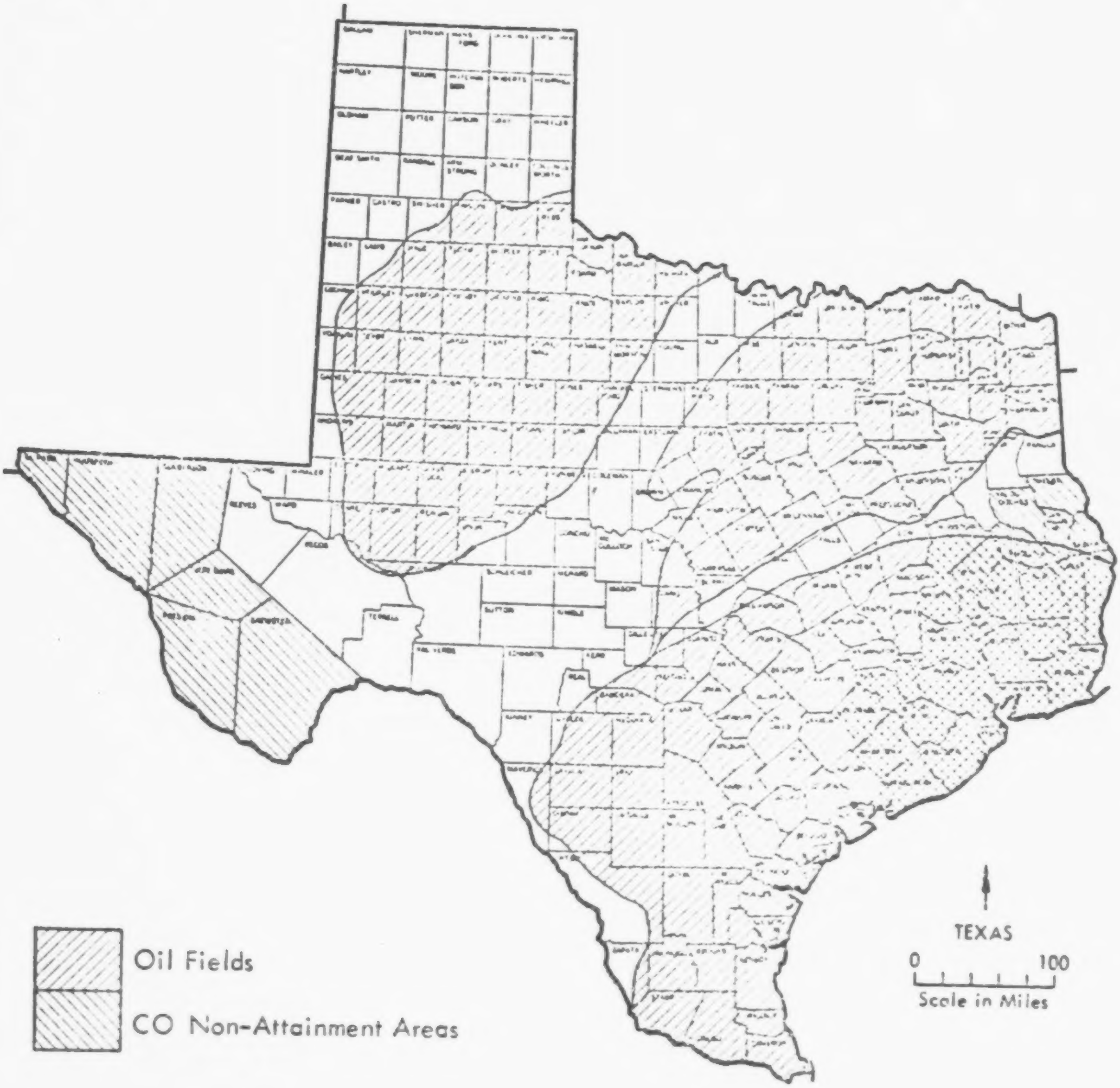

Oil Fields
CO Non-Attainment Areas
TEXAS
0
100
Scale in Miles

Figure I-9 - Locations of Existing Oil Fields and CO Non-attainment Areas (Texas)

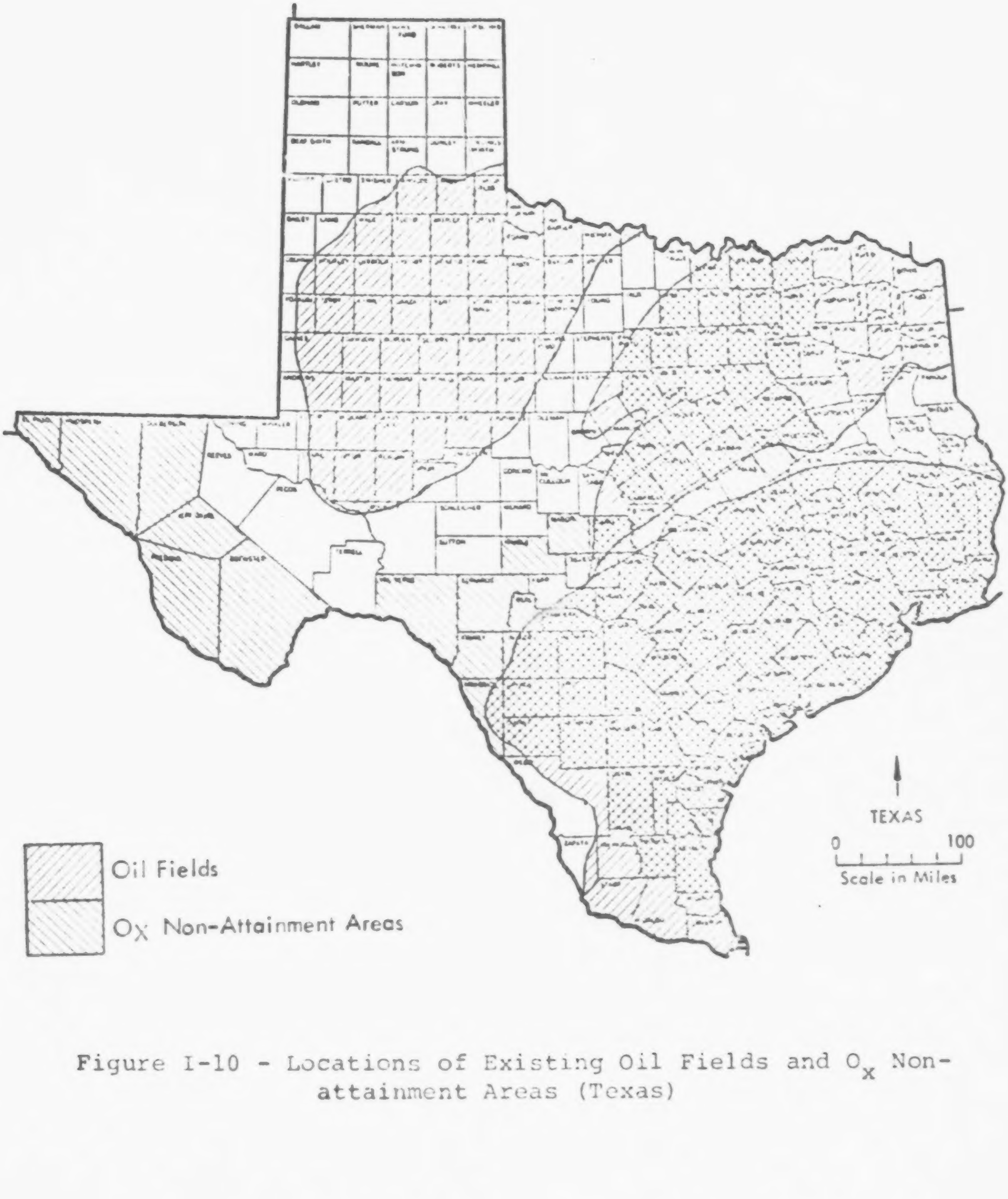
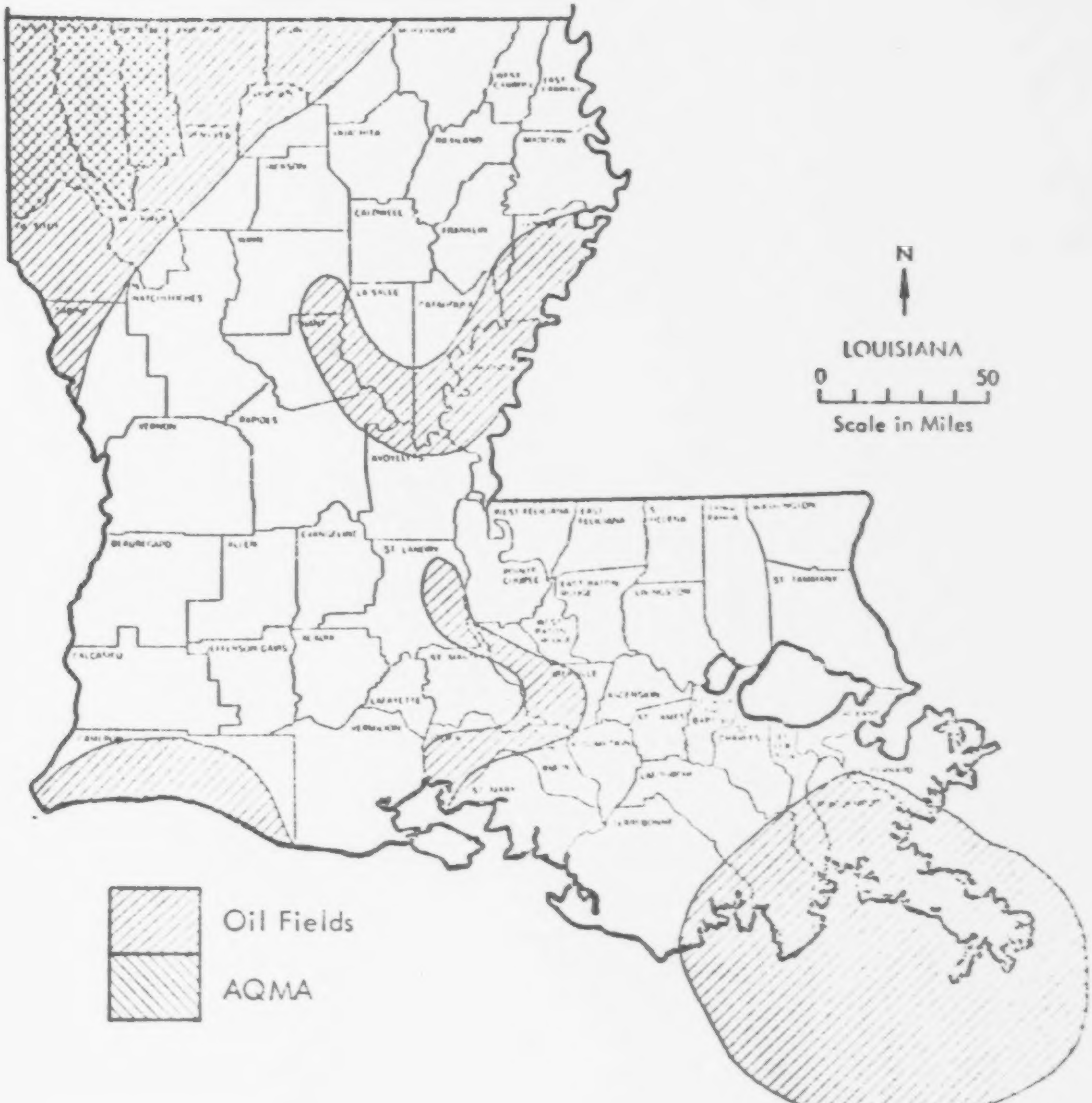

TEXAS
0
100
Scale in Miles
Oil Fields
OX Non-Attainment Areas

Figure I-10 - Locations of Existing Oil Fields and $O_x$ Non-attainment Areas (Texas)


N
LOUISIANA
0
50
Scale in Miles
Oil Fields
AQMA

| AQMA | AQMA Number | POLLUTANTS | | | | |
|---|---|---|---|---|---|---|
| | | PM | $SO_2$ | CO | $O_X$ | $NO_2$ |
| Louisiana | | | | | | |
| Shreveport | 022A | X | | | | |

Figure I-11 - Locations of Existing Oil Fields and AQMA (Louisiana)

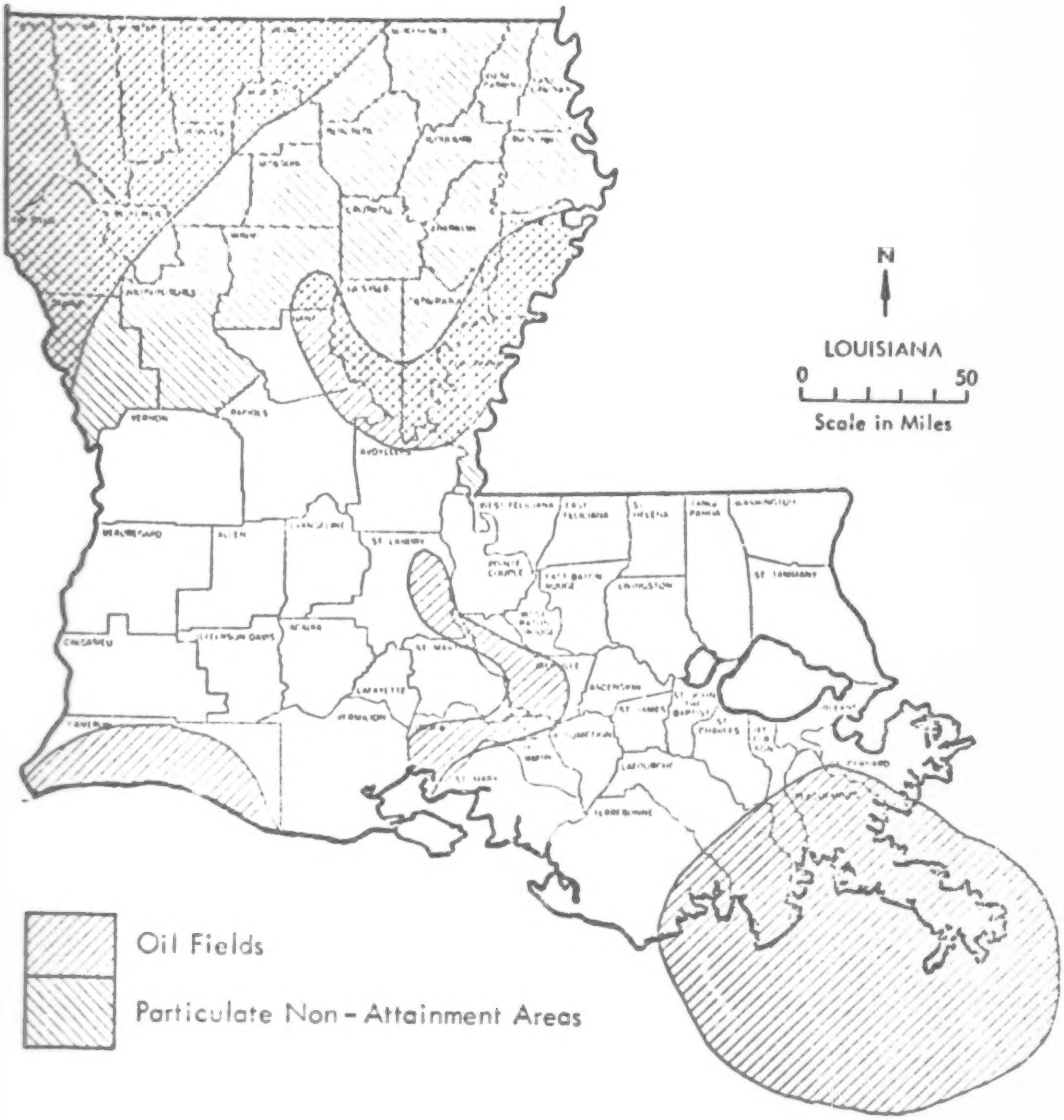

N
LOUISIANA
0
50
Scale in Miles
VERNON
RAPIDES
AVOYELLES
BEAUREGARD
ALLEN
EVANGELINE
ST. LANDRY
CALCASIEU
JEFFERSON DAVIS
ACADIA
LAFAYETTE
VERMILION
CAMERON
ST. MARY
WEST FELICIANA
EAST FELICIANA
ST. HELENA
WASHINGTON
ST. TAMMANY
LIVINGSTON
ASCENSION
ST. JAMES
ST. CHARLES
LAFOURCHE
TERREBONNE
Oil Fields
Particulate Non-Attainment Areas

Figure I-12 - Locations of Existing Oil Fields and Particulate Nonattainment Areas (Louisiana)

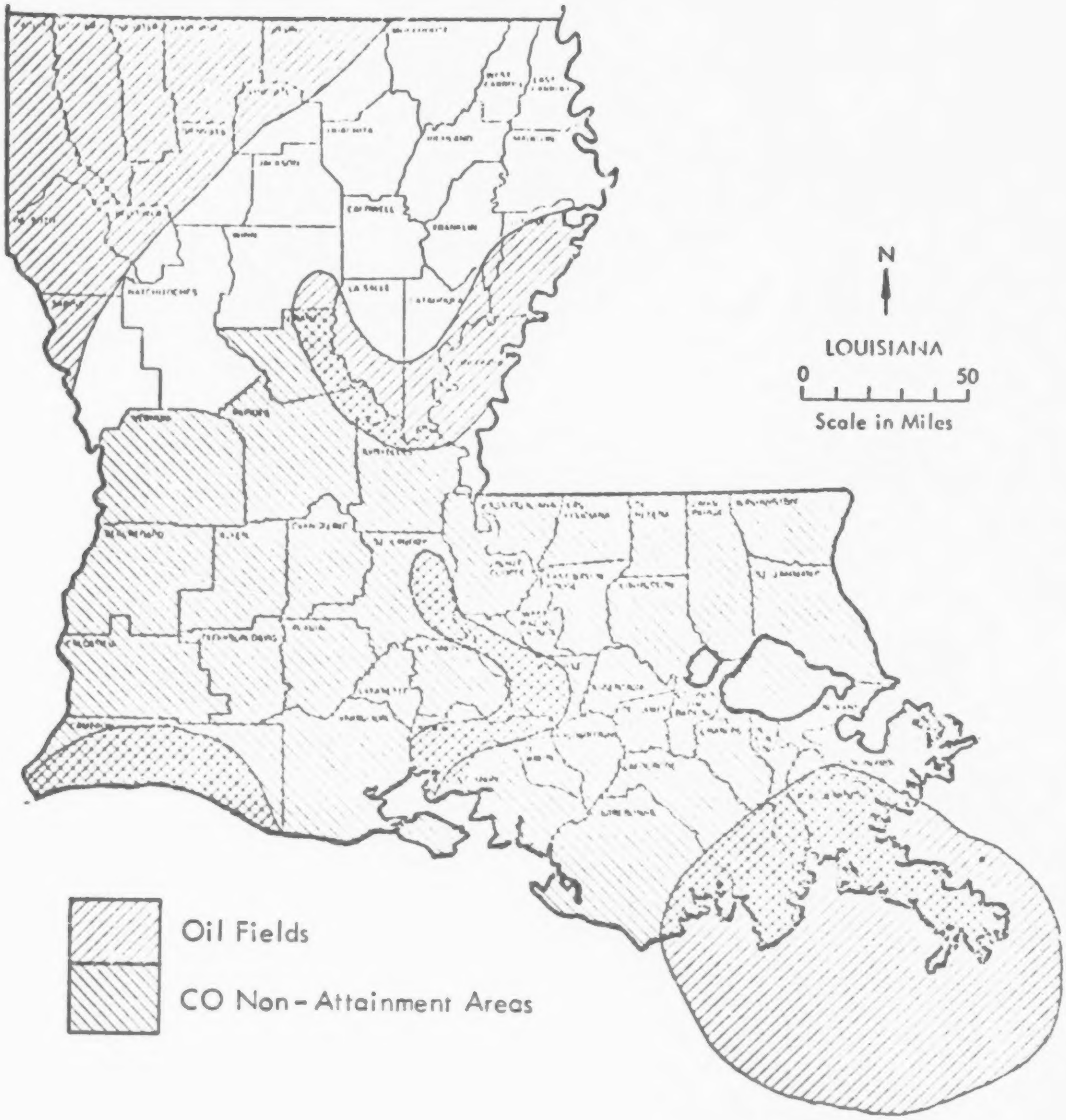

N
LOUISIANA
0
50
Scale in Miles
Oil Fields
CO Non-Attainment Areas

Figure I-13 - Locations of Existing Oil Fields and CO Non-attainment Areas (Louisiana)

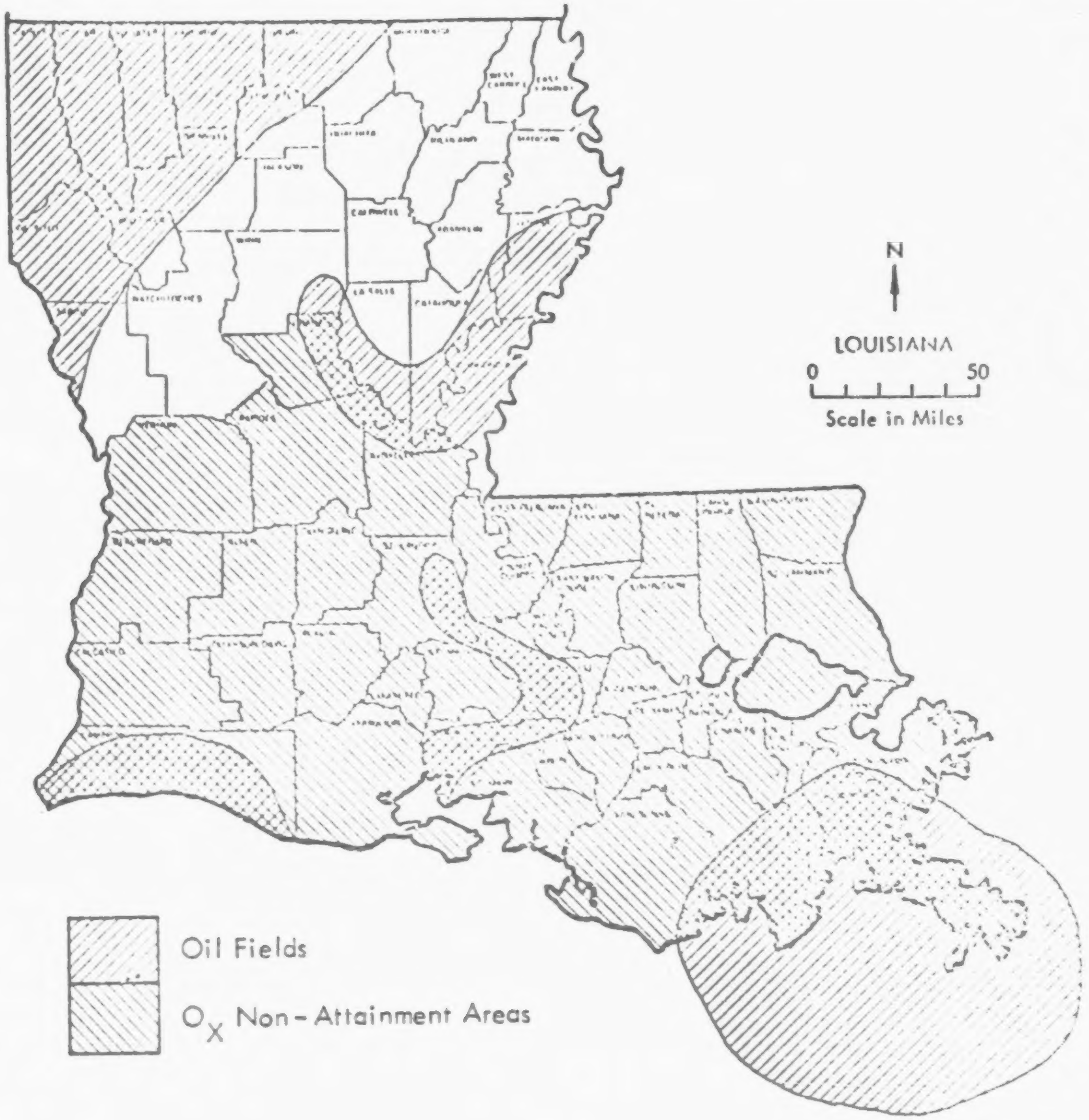
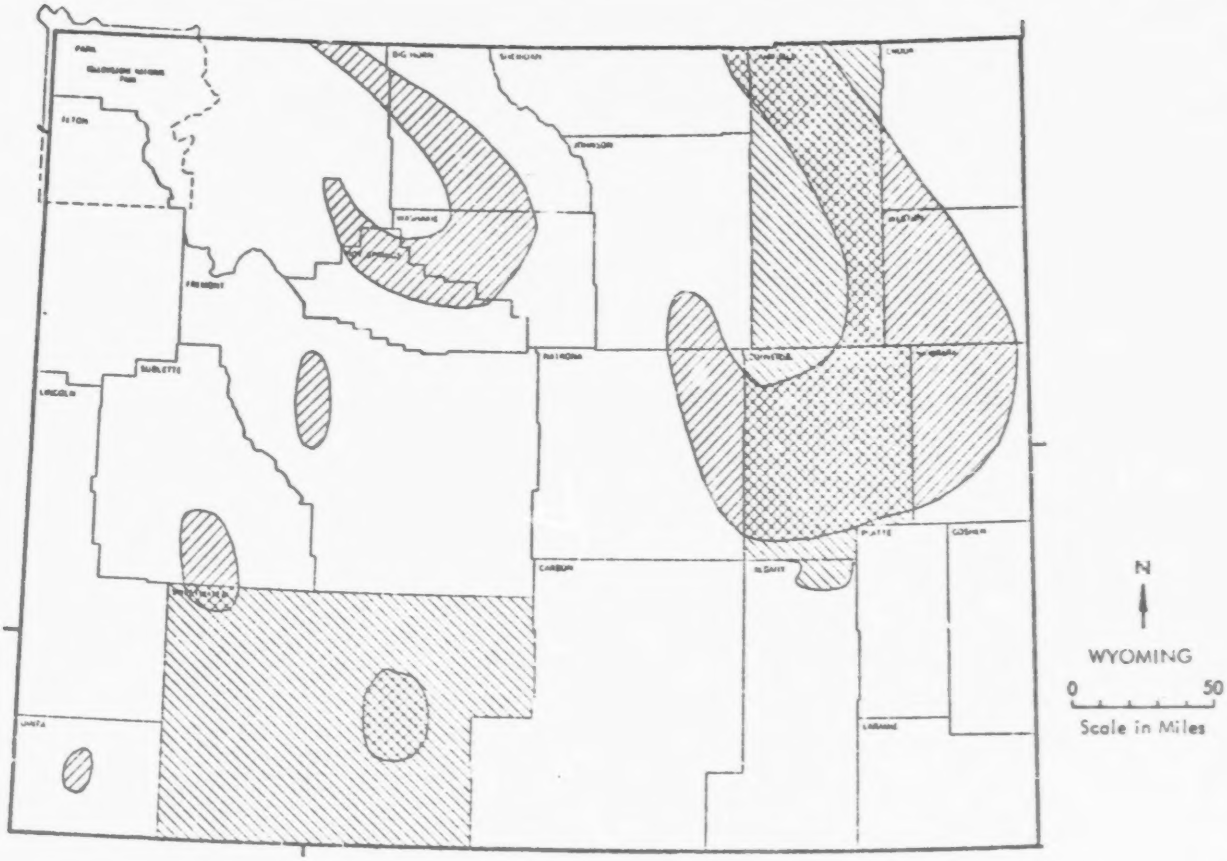

N
LOUISIANA
0
50
Scale in Miles
Oil Fields
$O_X$ Non-Attainment Areas

Figure I-14 - Locations of Existing Oil Fields and $O_x$ Non-attainment Areas (Louisiana)


PARK
YELLOWSTONE NATIONAL PARK
BIG HORN
SHERIDAN
CROOK
TETON
JOHNSON
WASHAKIE
HOT SPRINGS
WESTON
FREMONT
SUBLETTE
LINCOLN
NATRONA
CONVERSE
NIOBRARA
CARBON
ALBANY
PLATTE
GOSHEN
LARAMIE
UINTA
N
WYOMING
0
50
Scale in Miles

| AQMA | AQMA Number | POLLUTANTS | | | | |
|---|---|---|---|---|---|---|
| | | PM | $SO_2$ | CO | $O_X$ | $NO_2$ |
| Wyoming | | | | | | |
| Powder River Basin - Natural Resource Development Area | 241A | X | | | X | |
| Sweetwater - Natural Resource Development Area | 243A | X | X | | | |

▨ Oil Fields

▨ AQMA

Figure I-15 - Locations of Existing Oil Fields and AQMA (Wyoming)

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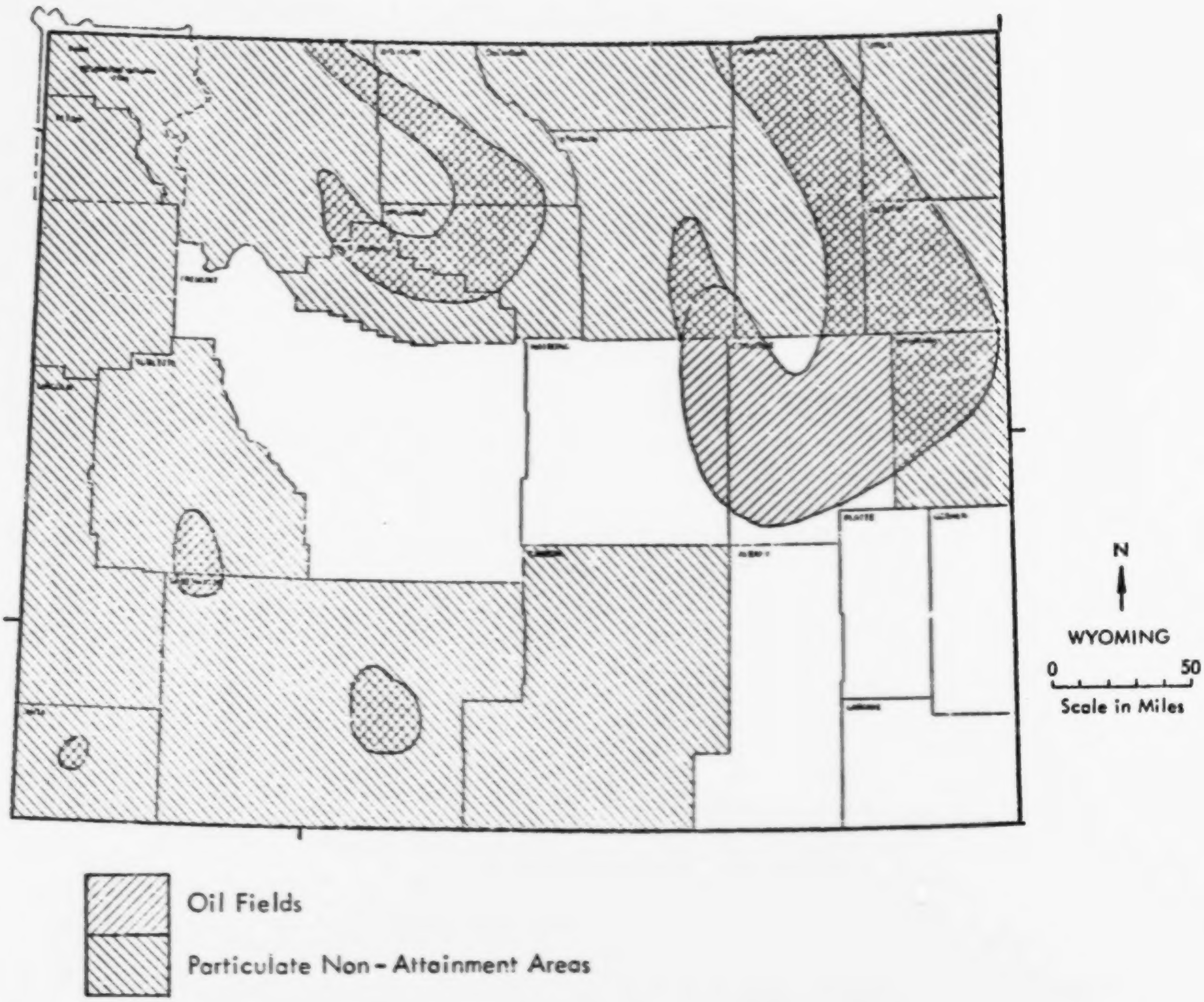
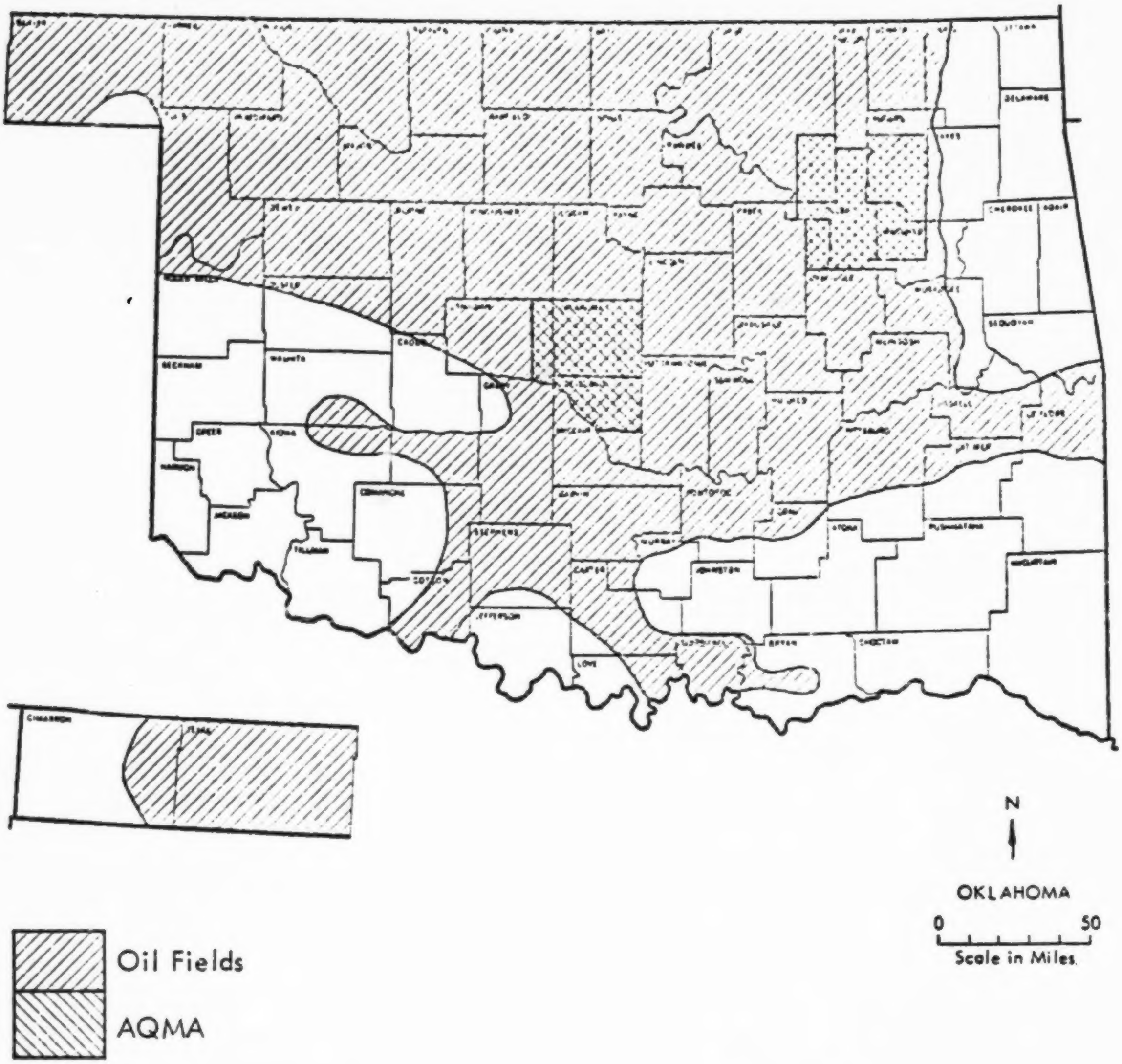

N
WYOMING
0
50
Scale in Miles
Oil Fields
Particulate Non-Attainment Areas

Figure I-16 - Locations of Existing Oil Fields and Particulate Nonattainment Areas (Wyoming)


N
OKLAHOMA
0
50
Scale in Miles
Oil Fields
AQMA

| AQMA | AQMA Number | POLLUTANTS | | | | |
|---|---|---|---|---|---|---|
| | | PM | $SO_2$ | CO | $O_X$ | $NO_2$ |
| Oklahoma | | | | | | |
| Central Oklahoma | 184A | X | | | X | |
| Tulsa | 186A | X | | | X | |

Figure I-17 - Locations of Existing Oil Fields and AQMA (Oklahoma)

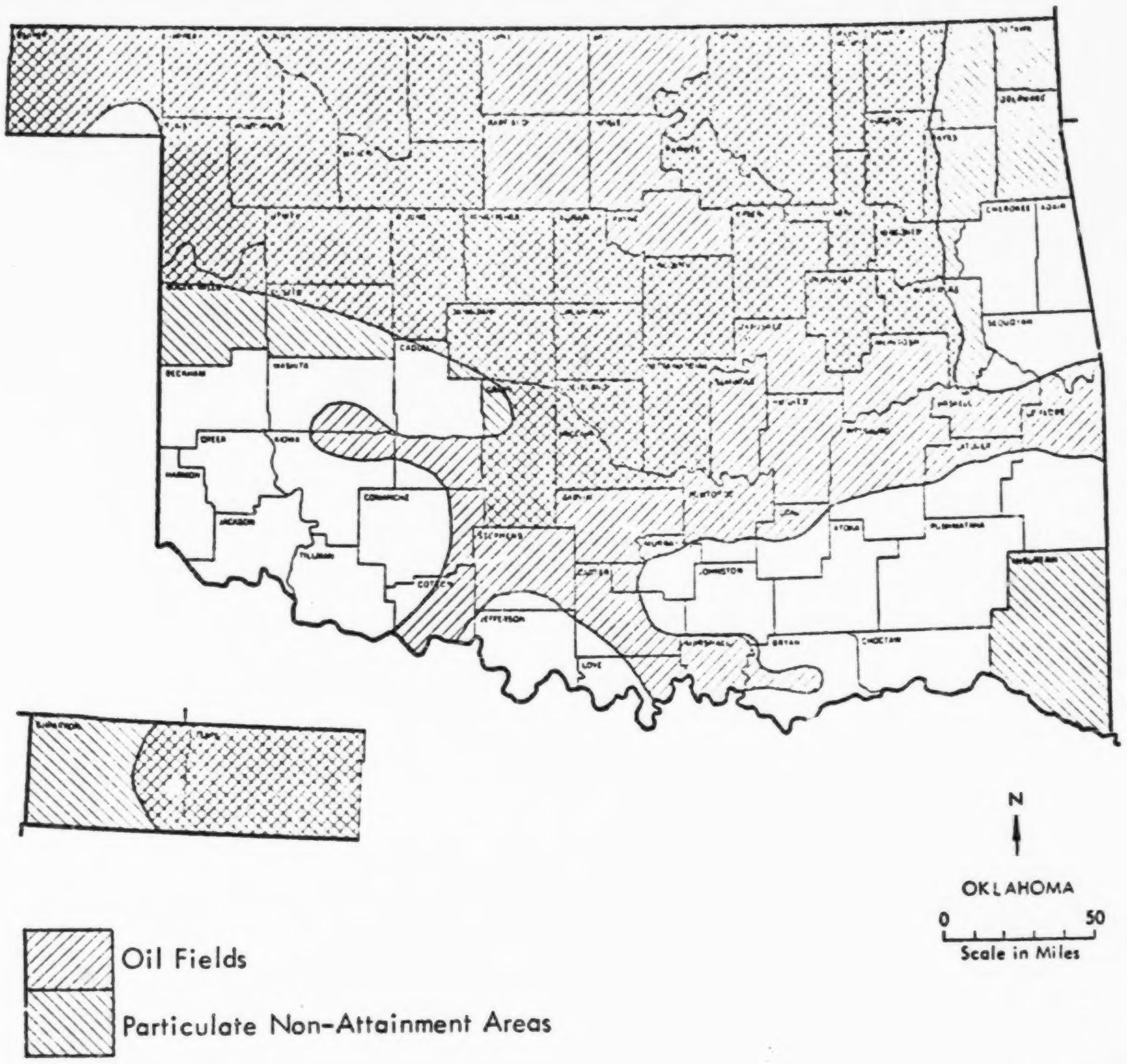

BECKHAM
WASHITA
CADDO
GREER
KIOWA
HARMON
JACKSON
TILLMAN
COMANCHE
COTTON
STEPHENS
JEFFERSON
CARTER
LOVE
PONTOTOC
JOHNSTON
ATOKA
PUSHMATAHA
BRYAN
CHOCTAW
McCURTAIN
SEQUOYAH
HASKELL
LE FLORE
LATIMER
N
OKLAHOMA
0
50
Scale in Miles
Oil Fields
Particulate Non-Attainment Areas

Figure I-18 - Locations of Existing Oil Fields and Particulate Nonattainment Areas (Oklahoma)

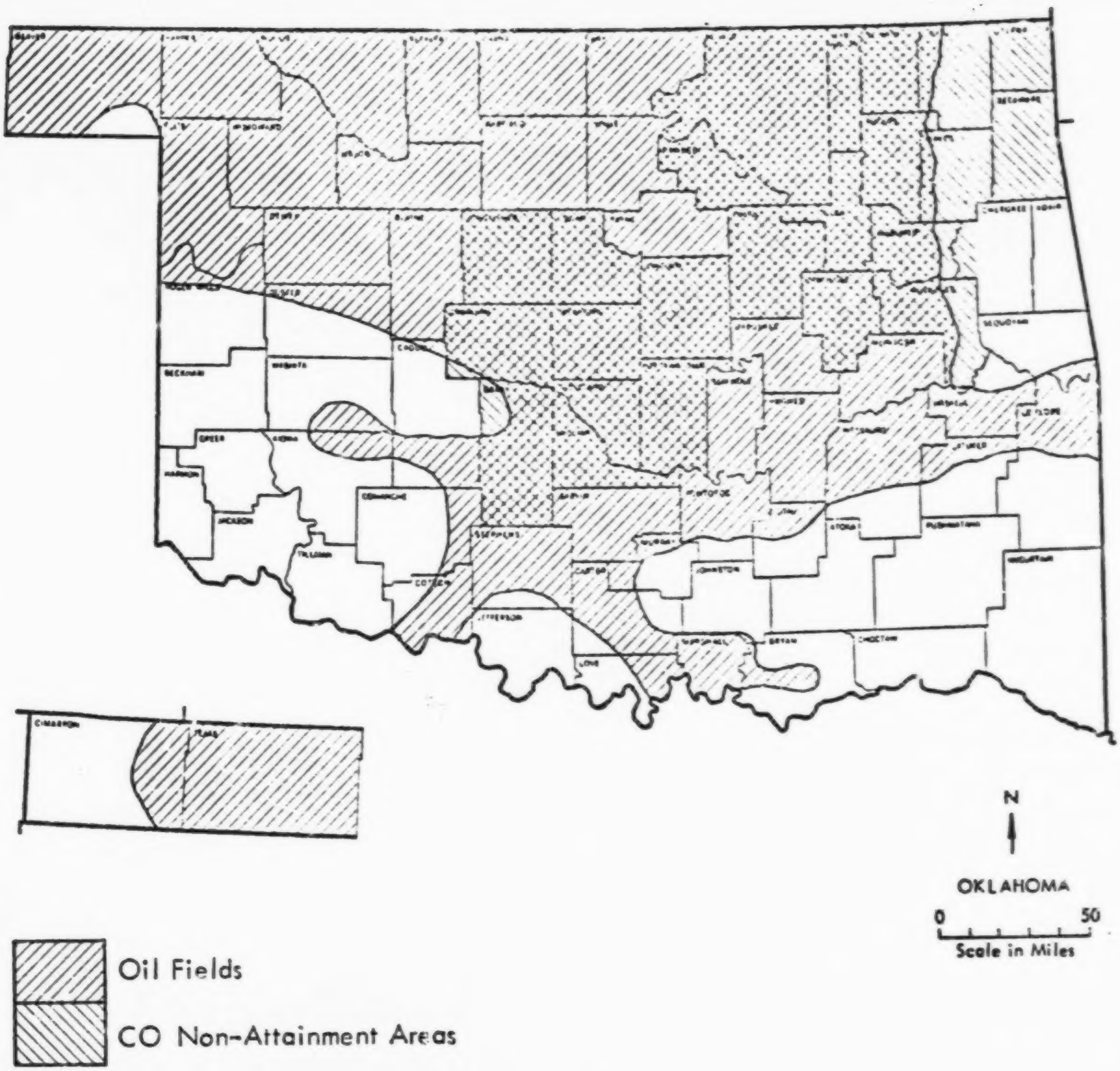

N
OKLAHOMA
0
50
Scale in Miles
Oil Fields
CO Non-Attainment Areas

Figure I-19 - Locations of Existing Oil Fields and CO Nonattainment Areas (Oklahoma)

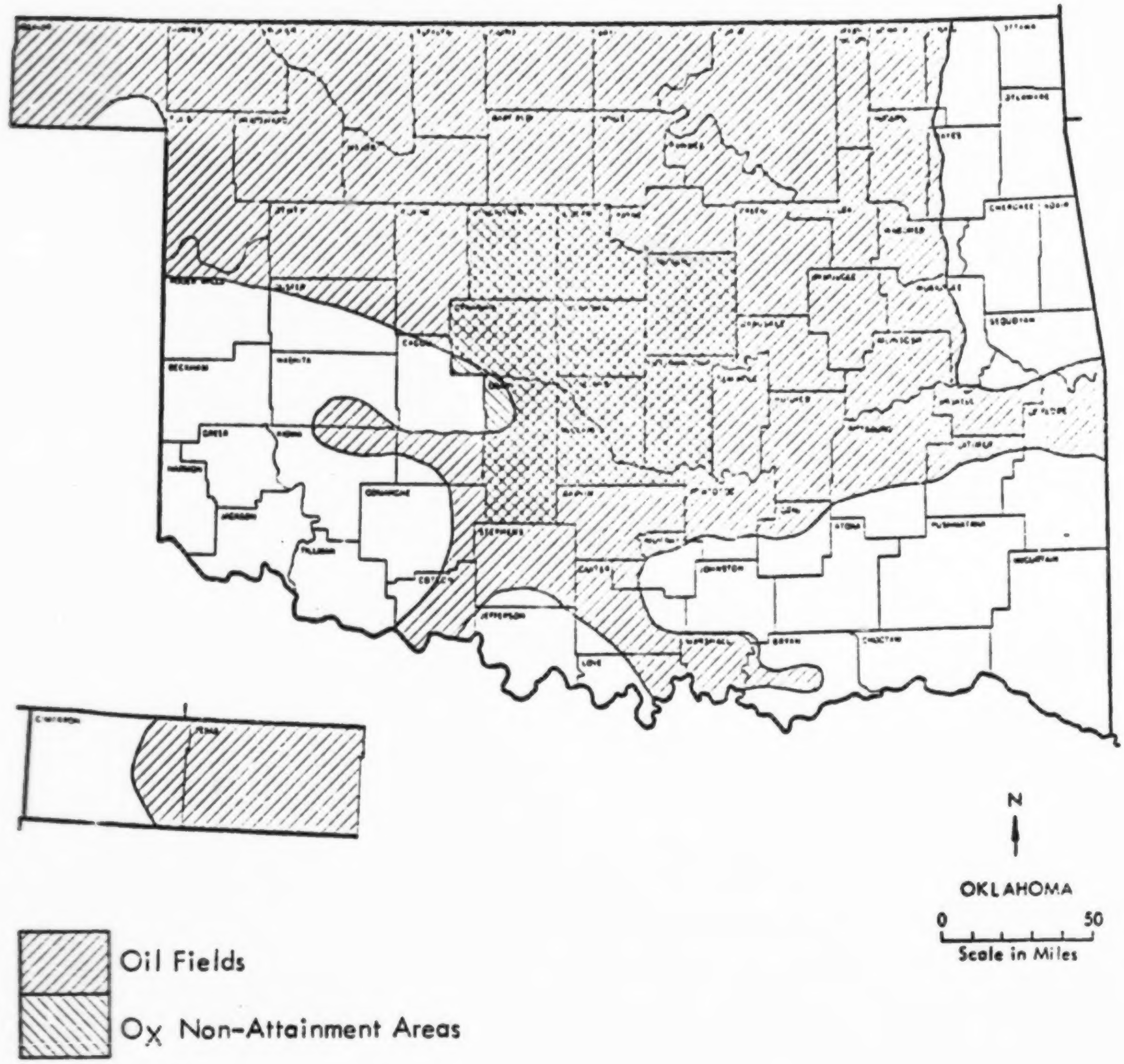

N
OKLAHOMA
0
50
Scale in Miles
Oil Fields
Ox Non-Attainment Areas

Figure I-20 - Locations of Existing Oil Fields and $O_x$ Nonattainment Areas (Oklahoma)

# APPENDIX J

# DESCRIPTION OF THE ENVIRONMENT AFFECTED

# APPENDIX J

## DESCRIPTION OF THE ENVIRONMENT AFFECTED

The proposed oil pricing policies will have environmental implications for areas located over much of the United States. Therefore, the setting for potential environmental effects spans the entire country. The approach taken to describe the existing environment focuses on those characteristics which will affect the nature and degree of impact resulting from the proposed action, such as seismic risk or wind patterns, and those features which will be impacted, such as air quality, or water quality. A brief overview of the environment at the national and Demand Region levels is provided first to describe general physical, biological, and socioeconomic features and trends across the United States. Then those sections of the country expected to be most affected by the pricing changes, namely, offshore and areas where tertiary recovery methods will be applied, are discussed in greater detail. These areas include two coastal locations (Gulf of Mexico and California) and inland areas in Texas, Southern California, Louisiana, Wyoming, and Oklahoma. Those areas not affected by the pricing policies (notably Alaska) are not described.

### A. National and Regional Overview

#### 1. Air Quality

A series of maps has been prepared which display the most recent data concerned with the nation's progress in attaining the National Ambient Air Quality Standards (NAAQS). The first series (Figures J-1 through J-5) portray those Air Quality Control Regions (AQCR) that are known to have violated the NAAQS in 1974.[1] Normally, there are several monitoring stations in each AQCR. If any one of these stations violated a NAAQS for any of the averaging periods, then the entire region was determined to be in violation. It should be noted that these figures are concerned with violations of the primary standards only, with no comments regarding the secondary standards, or any local or state air quality standards.

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[1] U.S. Environmental Protection Agency, Monitoring and Air Quality Trends Report, 1974, EPA Report 450/1-76-001, February 1976.

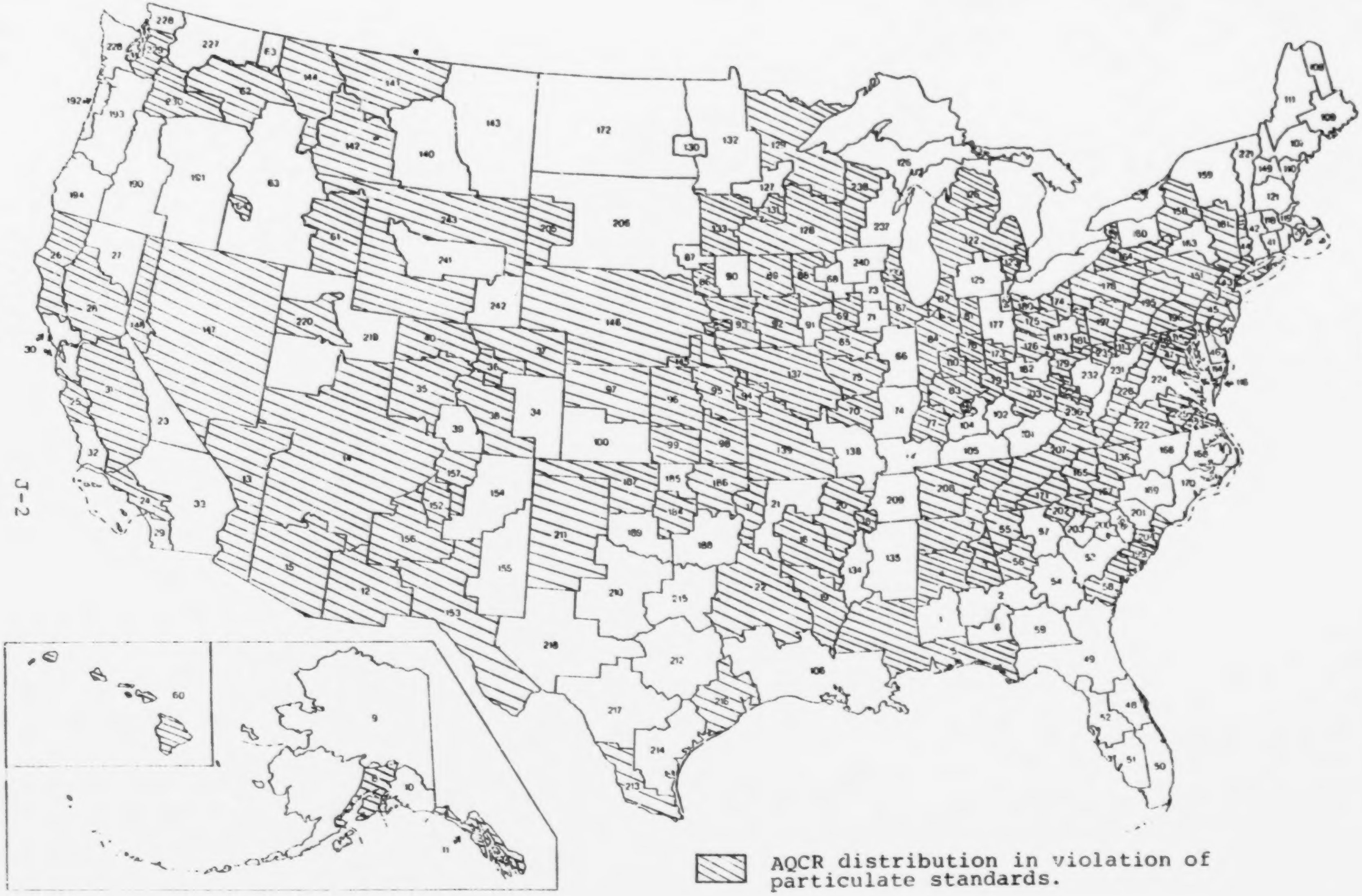
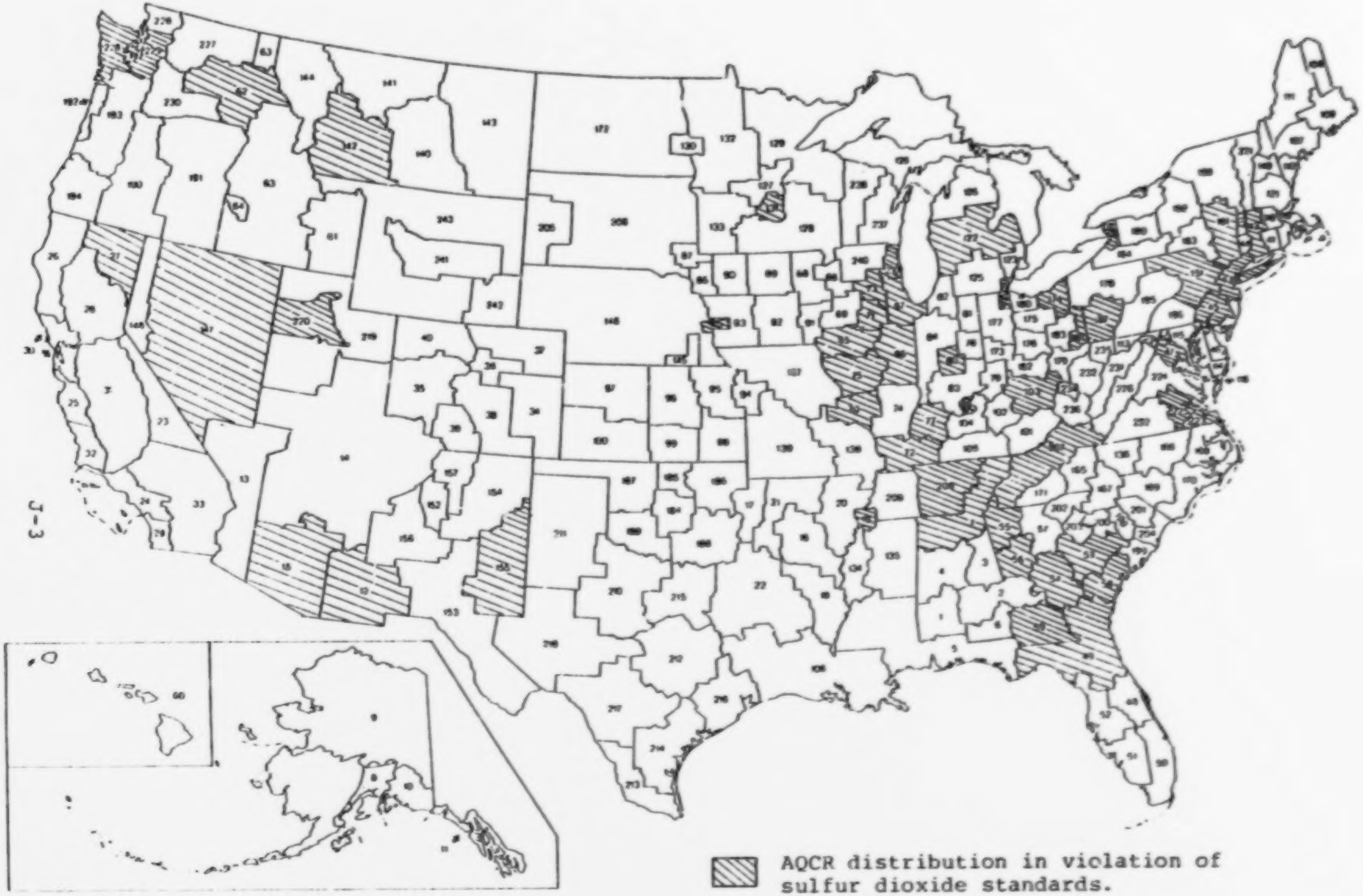
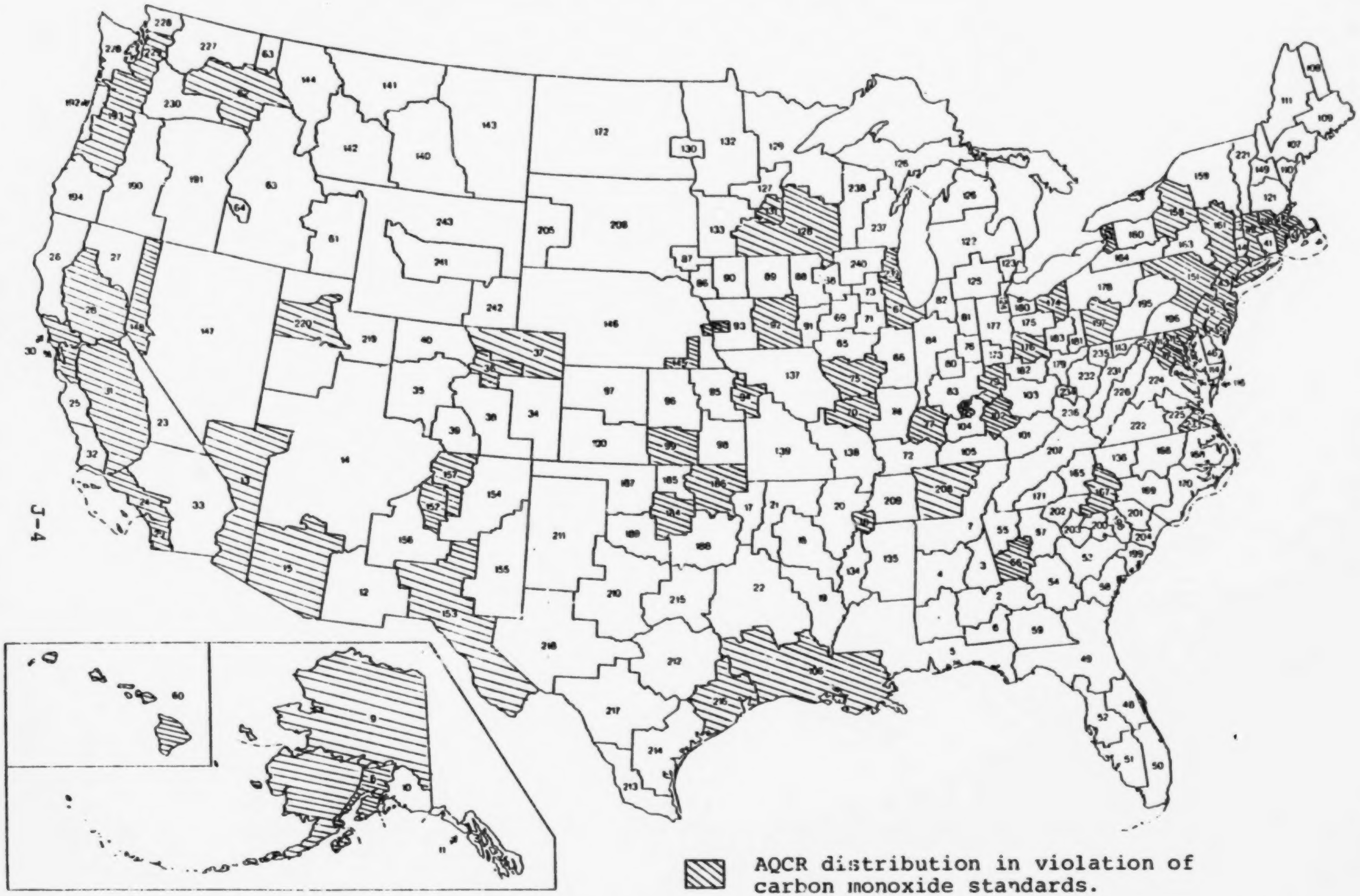

▨ AQCR distribution in violation of particulate standards.

Figure J-1. Distribution of AQCR's in the United States that were in violation of national particulate standards in 1974.



▨ AQCR distribution in violation of sulfur dioxide standards.

Figure J-2. Distribution of AQCR's in the United States that were in violation of national sulfur dioxide standards in 1974.



▨ AQCR distribution in violation of carbon monoxide standards.

Figure J-3. Distribution of AQCR's in the United States that were in violation of national carbon monoxide standards in 1974.

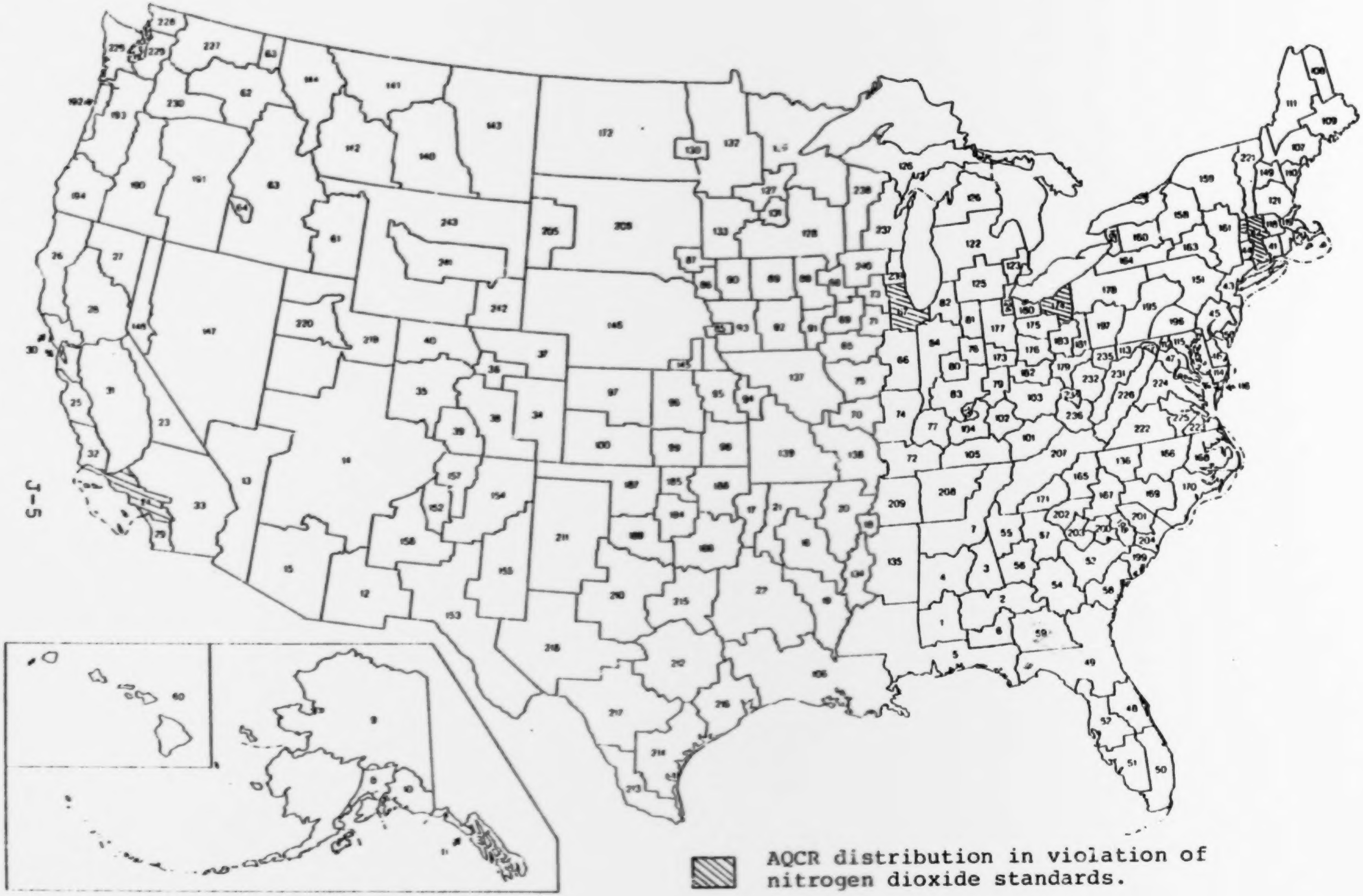

▨ AQCR distribution in violation of nitrogen dioxide standards.

Figure J-4. Distribution of AQCR's in the United States that were in violation of national nitrogen dioxide standards in 1974.

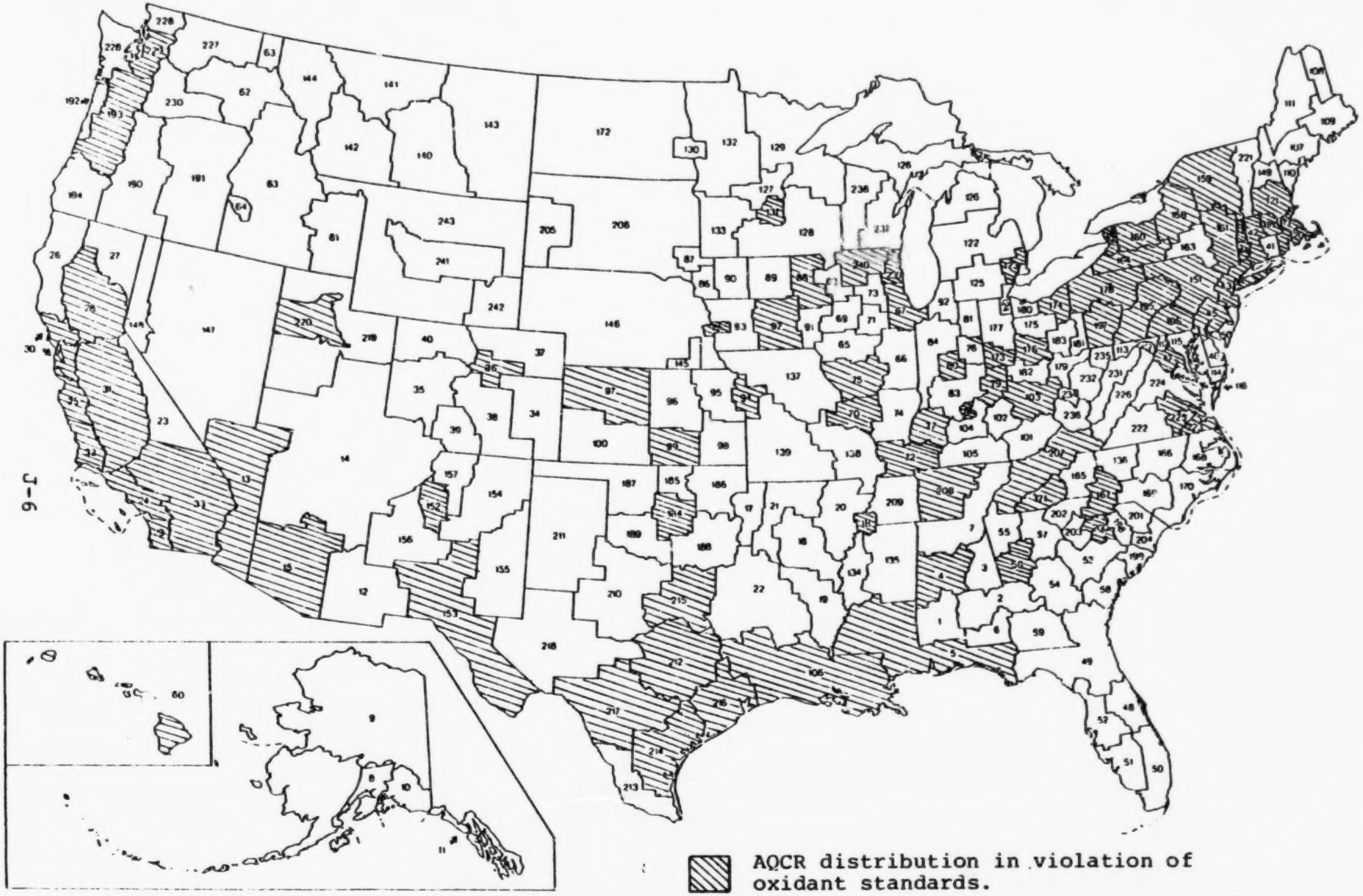

▧ AQCR distribution in violation of oxidant standards.

Figure J-5. Distribution of AQCR's in the United States that were in violation of national oxidant standards in 1974.

There are many instances where an AQCR has not been placed in violation when, in fact, it is quite possible that it was. This is the result of two factors: incomplete monitor coverage, and incomplete data retrieval from those monitors reporting. Therefore, these maps should be interpreted as showing regions of known violations, rather than a display of regions that are in NAAQS compliance.

Regions in violation of the nitrogen dioxide standards are particularly few in number; however, this may be in some respect an outcome of the uncertainty surrounding the problem of establishing a new reference method for measuring nitrogen dioxide. The areal extent of oxidant, carbon monoxide, and sulfur dioxide violations are all of the same magnitude.

Similar data for 1975 still remain incomplete, but violation estimates had been made by the EPA in November of 1975.[2] The suggested status of the nation's AQCR's for particulates, sulfur dioxide, and nitrogen dioxide are displayed in Figures J-6 through J-8. Again, the most pervasive problem is that of particulate matter. A few AQCR's found to be in violation in 1974 have since either improved their air quality, or moved their monitoring sites, since they are now apparently in compliance. There are also a number of regions which are now estimated to be in violation that were previously in compliance, or possibly experiencing reporting problems. So these new "offenders" may have been able to locate some new problem areas within their boundaries. One important difference between the 1974 maps and those of 1975 is that the latter were determined by state and AQCR, so several interstate AQCR's are characterized by more than one compliance classification. This helps to locate only those portions of the larger AQCR's that experience difficulty.

The estimated 1975 sulfur dioxide violators are significantly fewer in number than those in 1974. Some of the reduction may be short-lived, however, if many of the "uncertain" regions become violators. Nonetheless, the progress in many areas is impressive.

Nitrogen dioxide violators are apparently increasing their number. A higher degree of diligence in obtaining data may account for some of this, but it is generally accepted that the nitrogen dioxide problem is growing in

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[2] "Estimated Status of Attainment of National Ambient Air Quality Standards by Air Quality Control Regions in 1975," Environment Reporter, February 13, 1976.

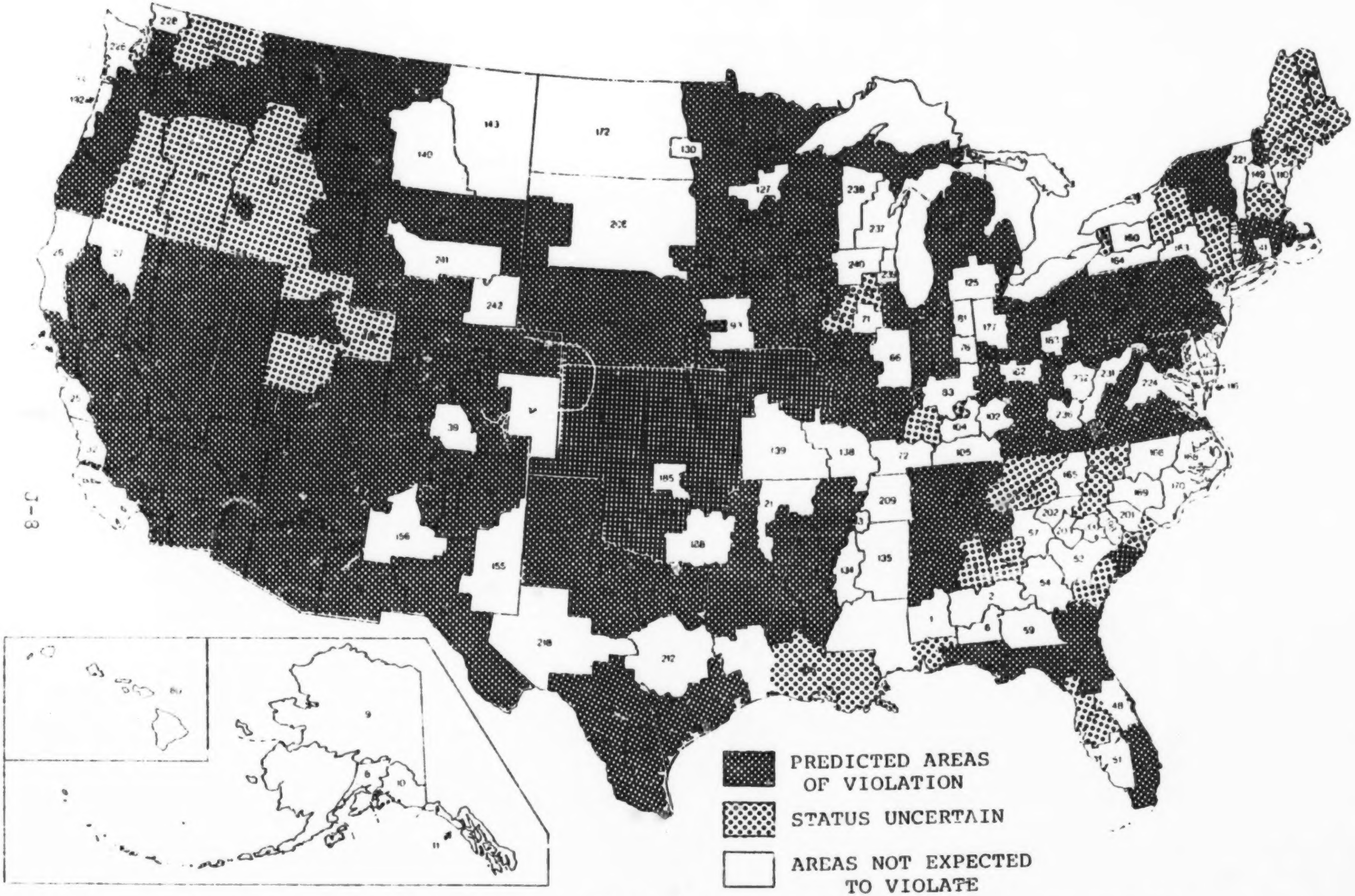

PREDICTED AREAS OF VIOLATION
STATUS UNCERTAIN
AREAS NOT EXPECTED TO VIOLATE
228
226
192
143
172
130
140
127
238
237
240
208
201
242
91
71
66
125
81
177
76
167
122
232
231
224
83
104
102
236
105
139
138
72
166
168
165
185
21
209
169
170
202
201
57
52
128
134
135
156
155
54
2
1
6
59
218
212
48
51
39
221
149
110
160
164
161
41
26
27
9
8
10
11

Figure J-6. Estimated status of attainment of national ambient air quality standards for total suspended particulates by air quality control regions in 1975.

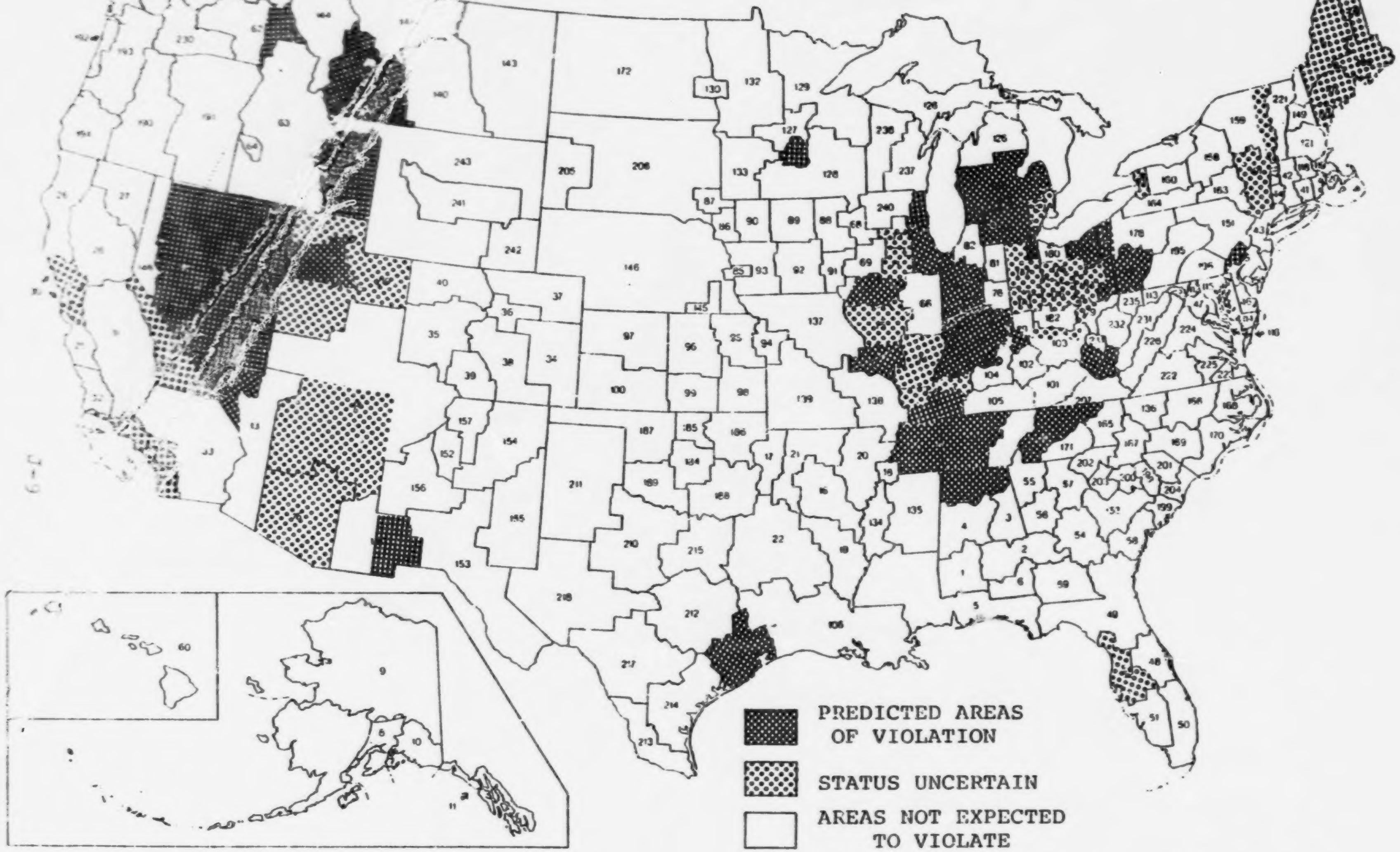

PREDICTED AREAS OF VIOLATION
STATUS UNCERTAIN
AREAS NOT EXPECTED TO VIOLATE

Figure J-7. Estimated status of attainment of national ambient air quality standards for $SO_2$ by air quality control regions in 1975.

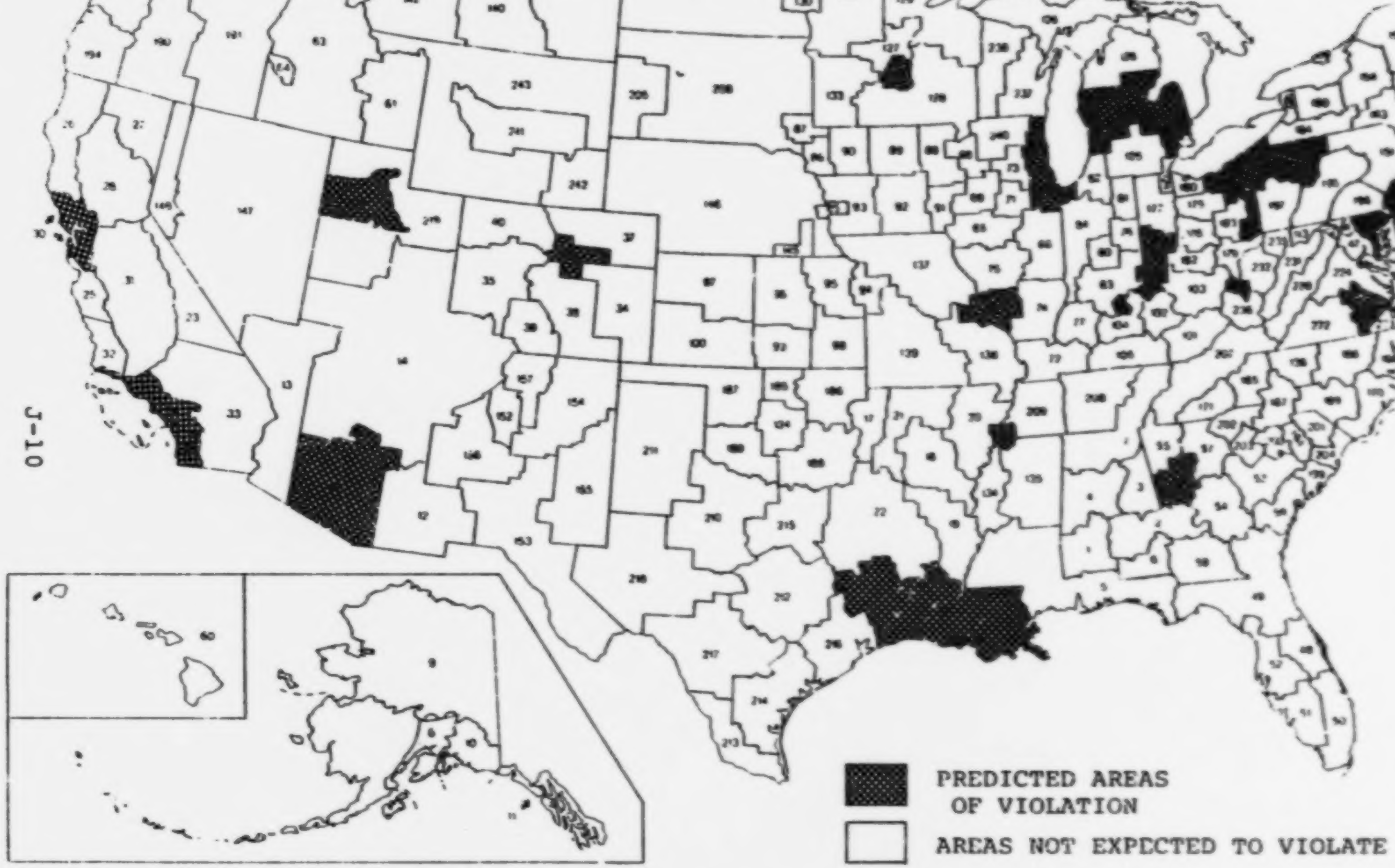

PREDICTED AREAS OF VIOLATION
AREAS NOT EXPECTED TO VIOLATE

Figure J-8. Estimated status of attainment of national ambient air quality standards for $NO_X$ by air quality control regions in 1975.

the country. Note that none of the four areas designated in 1974 have been able to attain compliance in 1975. No compliance estimates are available for the other two pollutants.

Designated Air Quality Maintenance Areas (AQMA) provide another measure of what are thought to be areas of present and future air quality problems. These regions are typically clusters of several counties that are either currently violating the NAAQS, or are thought to be potential violators due to projected development trends. Their limited geographical extent is helpful in determining which sections of a rather large AQCR are actually contaminated. Figures J-9 through J-13 show the AQMA's which have been designated as problem areas for particulate matter, sulfur dioxide, nitrogen dioxide, photochemical oxidants, and carbon monoxide. Once again, particulates are associated with most of the AQMA's, with sulfur dioxide, oxidants, and carbon monoxide accounting for a considerably smaller number. Nitrogen dioxide AQMA's number five, with four corresponding to the AQCR's violating the standards in 1975, and three corresponding to those for 1974.

Areas that are currently violating the NAAQS's are regions that are sensitive to further pollutant loading. This, however, does not imply that areas with minor air quality problems are free to accept further emissions until the national primary standards are approached. The nonsignificant deterioration policy places limits on the incremental amount of degradation that is considered acceptable.

The EPA has set up a system of classification according to allowable air quality degradation consisting of three tiers. Initially, all areas of the country are placed in the Class II category, with further changes to either Class I or Class III made possible through state action after a public hearing. At the present time, however, the necessary legislation to enforce this policy is tied up in Congress. Both the House and the Senate have developed their own versions of the bill. The original descriptions of the three possible classes are as follows:

- Class I - Applies to areas in which practically any air quality deterioration would be considered significant, thus allowing little or no major energy or industrial development.

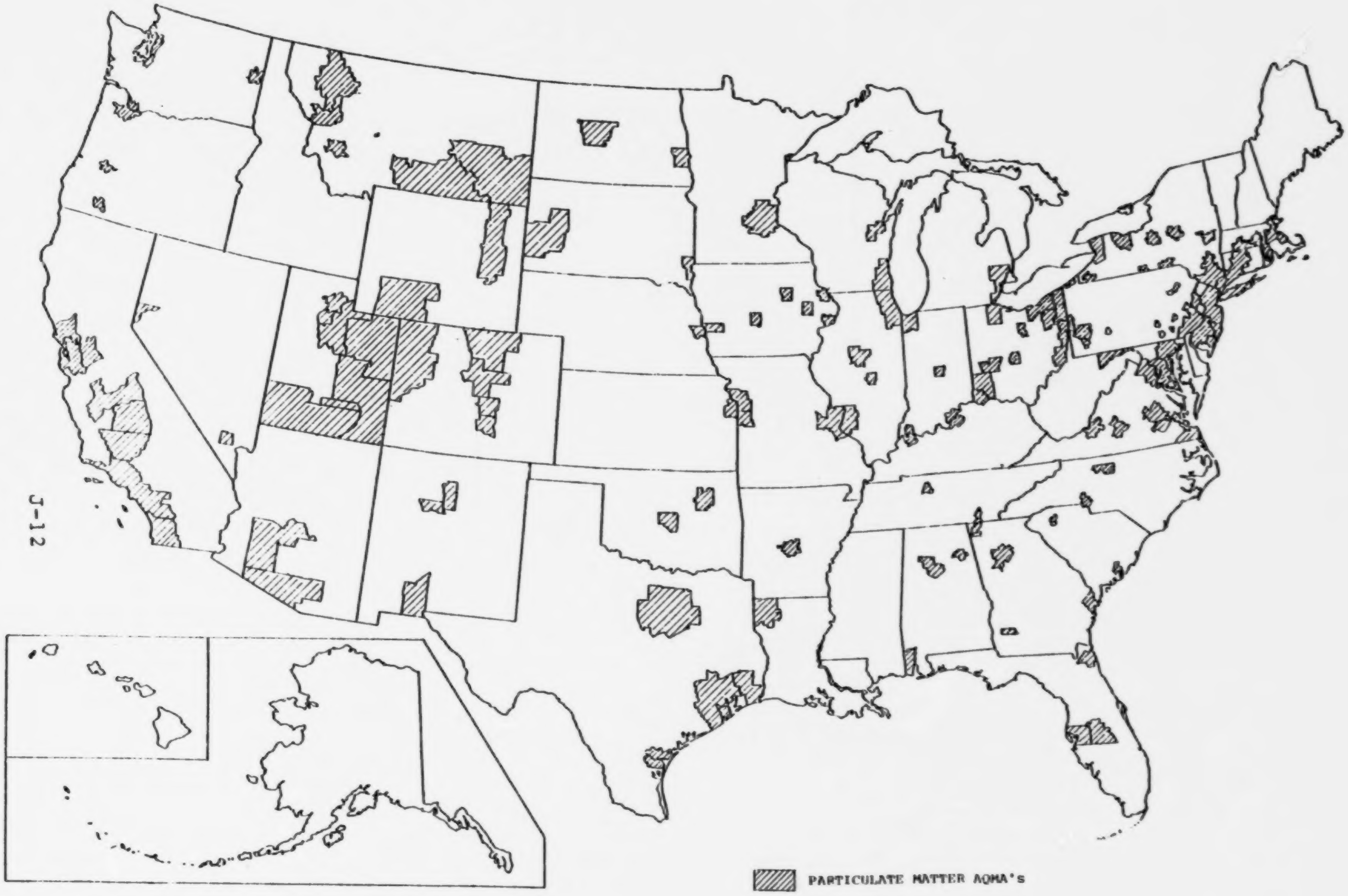

▨ PARTICULATE MATTER AQMA's

Figure J-9. Designated Air Quality Maintenance Areas based on current and expected levels of suspended particulate matter.

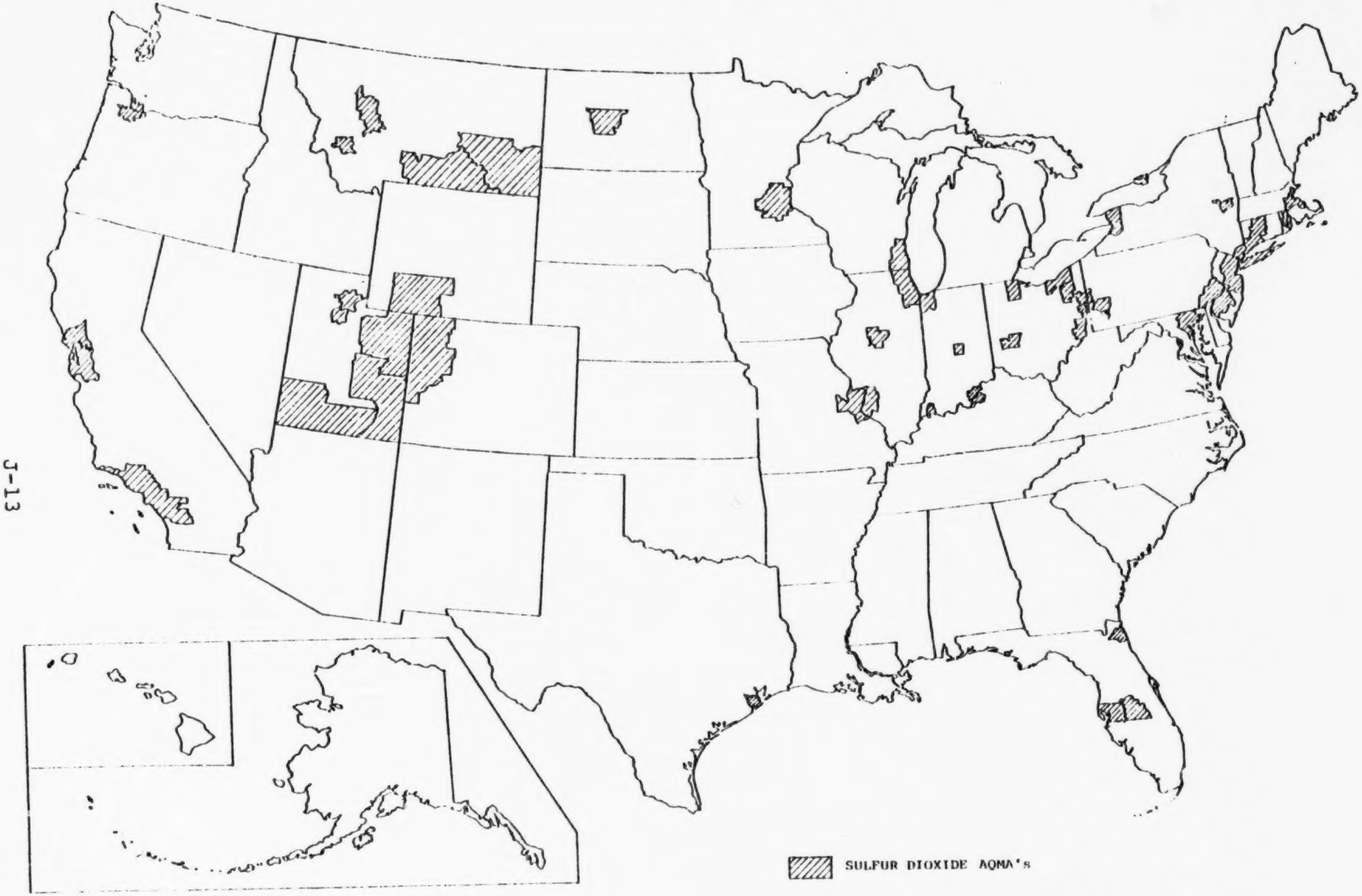

▨ SULFUR DIOXIDE AQMA's

Figure J-10. Designated Air Quality Maintenance Areas based on current and expected levels of sulfur dioxide.

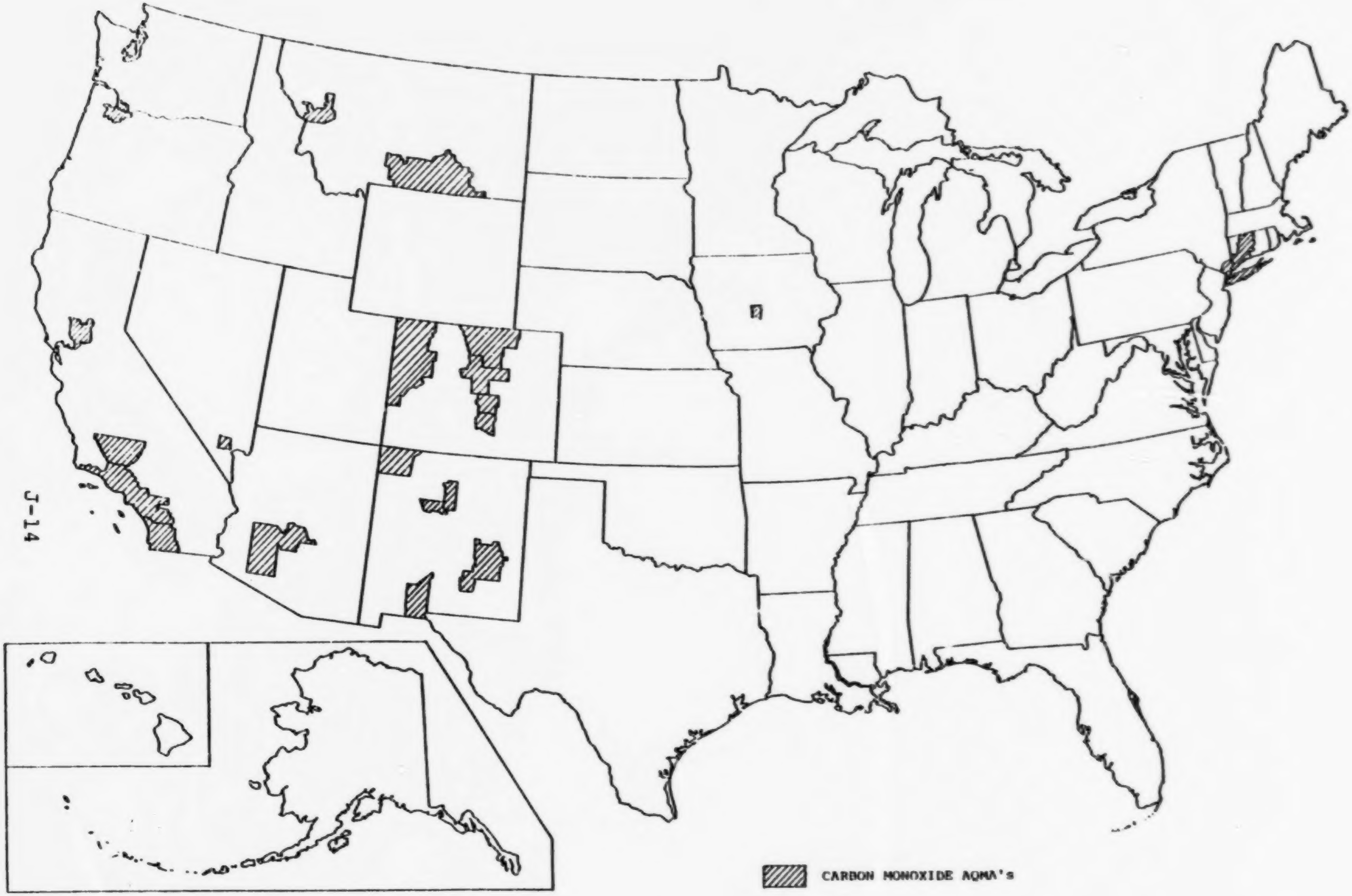
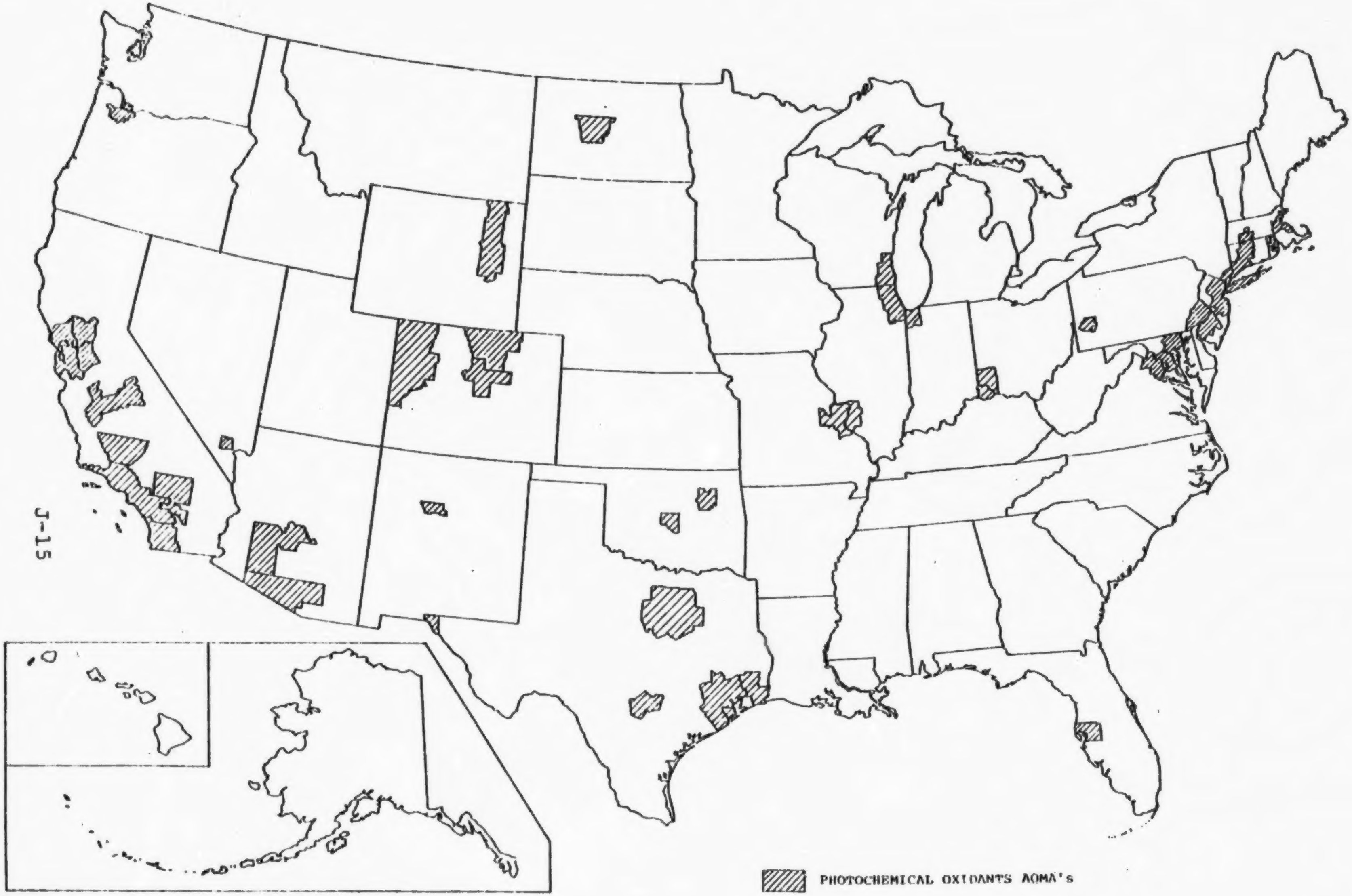

▨ CARBON MONOXIDE AQMA's

Figure J-11. Designated Air Quality Maintenance Areas based on current and expected levels of carbon monoxide.



▨ PHOTOCHEMICAL OXIDANTS AQMA's

Figure J-12. Designated Air Quality Maintenance Areas based on current and expected levels of photochemical oxidants.

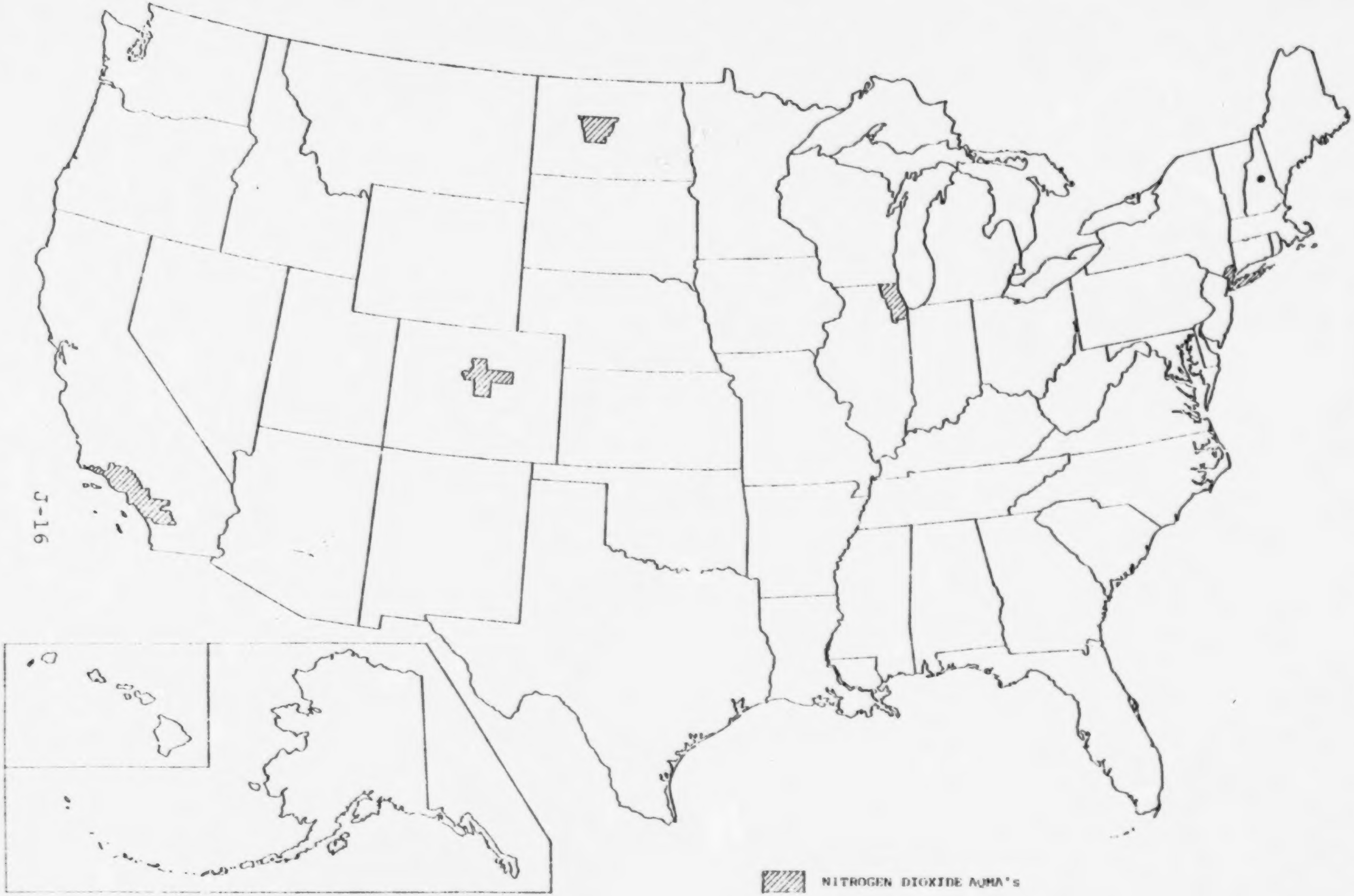

▨ NITROGEN DIOXIDE AQMA's

Figure J-13. Designated Air Quality Maintenance Areas based on current and expected levels of nitrogen dioxide.

J-13

- Class II - Applies to areas in which deterioration that would normally accompany moderate, well-controlled growth would not be considered significant.

- Class III - Applies to areas in which deterioration would be permitted to allow concentrated or very large-scale energy or industrial development, as long as the national secondary ambient air quality standards are not exceeded.

Table J-1 lists those lands which were thought to be candidates for the Class I revision process in the current regulations. The corresponding treatment of these lands under the House and Senate versions is also listed.[3] The numerical limits to the allowed deterioration for the three classes are presented in Table J-2. Since the original EPA regulations considered the policy to apply only to suspended particulate matter and sulfur dioxide, these are the only criteria pollutants considered. However, both the House and the Senate version would set limits on some others as well. These and other differences between the three versions are listed in Table J-3.

Restrictions imposed by the Class I designation are clearly severe for activities within their boundaries, but activities outside of the Class I regions may also be affected. Not only must the incremental degradation of air quality in a Class II or III region conform to its own specified levels, but the distant downwind effect of these operations on nearby Class I areas must be considered as well.

The regional analysis to follow divided the country into 10 Demand Regions. The relationship between these regions and the Air Quality Control Regions is illustrated in Figure J-14.

It is clear from Figures J-1 and J-6 that no Demand Region is free of areas of high ambient concentrations of suspended particulates (based on data from 1974 and 1975). However, Region 8 appears to be the most uniformly affected, followed closely by Regions 2 and 4.

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[3] U.S. Environmental Protection Agency and Federal Energy Administration, An Analysis of the Impact on the Electric Utility Industry of Alternative Approaches to Significant Deterioration, FEA/D-75/385, October 1975.

TABLE J-1

## CLASS I AREAS UNDER SENATE AND HOUSE APPROACHES TO SIGNIFICANT DETERIORATION

| LAND CATEGORY | SENATE | HOUSE |
|---|---|---|
| National Wilderness Area | Class I (5,000+ acres) | Class I; provision for redesignation as Class II (1,000+ acres) |
| National Parks | Class I (6,000+ acres) | Class I (25,000+ acres) provision for redesignation as Class II (1,000+ acres) |
| International Parks | Class I (5,000+ acres) | - |
| National Memorial Parks | Class I (5,000+ acres) | - |
| National Wilderness Preservation Systems | - | Class I (25,000+ acres) |
| National Reserves, Monuments and Recreation Areas | - | Class I; provision for redesignation as Class II (10,000+ acres) |
| New National Parks | Class I or Class II (5,000+ acres) | - |
| New National Wilderness Areas | Class I or Class II (5,000+ acres) | - |
| Primitive Areas | - | Class I; provision for redesignation as Class II (10,000+ acres) |
| Other National Areas of Special Environmental Concern | - | Class I or Class II (10,000+ acres) |

## TABLE J-2

## ALLOWABLE AIR QUALITY INCREMENTS UNDER ALTERNATIVE SIGNIFICANT DETERIORATION PROPOSALS

($\mu g/m^3$)

| | CLASS I | | | CLASS II | | | CLASS III | | |
|---|---|---|---|---|---|---|---|---|---|
| POLLUTANT STANDARD | EPA REGS. | SENATE PROPOSAL | HOUSE PROPOSAL[1] | EPA REGS. | SENATE PROPOSAL | HOUSE PROPOSAL[1] | EPA REGS.[2] | SENATE PROPOSAL | HOUSE PROPOSAL |
| Sulfur Dioxide | | | | | | | | | |
| Annual | 2 | 2 | 1.6 | 15 | 15 | 20 | 80 | No | 40 |
| 24-hour | 5 | 5 | 7.3 | 100 | 100 | 91 | 365 | Class III | 183 |
| 3-hour | 25 | 25 | 26 | 700 | 700 | 325 | 1,300 | | 650 |
| Total Suspended Particulates | | | | | | | | | |
| Annual | 5 | 5 | 7.5 | 10 | 10 | 19 | 75 | No | 38 |
| 24-hour | 10 | 10 | 15 | 30 | 30 | 38 | 150 | Class III | 75 |

[1] The increments for the House proposal are based on limitations of 2% of NAAQS for Class I, 25% for Class II, and 50% for Class III, except that the limit for total suspended particulates in Class I is 10% of NAAQS. In addition, the House proposal stipulates that the concentration of all pollutants cannot exceed 75% of the national ambient air quality standards in any of the classes.

[2] EPA's Class III allows degration up to the NAAQS:

| | Sulfur Dioxide | TSP |
|---|---|---|
| Annual | 80 (primary) | 75 (primary) |
| 24-hour* | 365 (primary) | 150*(secondary) |
| 3-hour* | 1300 (secondary) | |

*The 24-hour and 3-hour standards are not to be exceeded more than once per year. There are no primary 3-hour standards for sulfur dioxide and particulates, nor is there a 24-hour primary standard for particulates.

## TABLE J-3

## SUMMARY OF MAJOR DIFFERENCES OF ALTERNATIVE APPROACHES TO SIGNIFICANT DETERIORATION

| ISSUES | EPA | HOUSE | SENATE |
|---|---|---|---|
| Sources Covered | 18 source categories | Any facility emitting more than 100 ton/yr of any regulated pollutant | Any facility emitting more than 100 ton/yr of any pollutant |
| Pollutants Covered | TSP and $SO_2$ | All | TSP, $SO_2$, others to be established later |
| Control Technology Requirements | Equivalent to NSPS where NSPS exist; and determined on a case-by-case basis where NPSP does not exist | None specified | Maximum degree of emission control possible; determined on a case-by-case basis |
| Class I areas | No mandatory (at state and Federal discretion with procedures for full public participation) | Designation of some areas as mandatory Class I and others as either Class I, II or III (see Table V-1) | Designation of some areas as mandatory Class I and others as either Class I or Class II (see Table V-1) |
| Class III Areas | Procedures for designation of areas as Class III | Procedures for designation of areas as Class III | No Provision for Class III |
| Numeric Limitations for Class I, II & III | See Table V-2 | See Table V-2 | See Table V-2 |
| Maximum Allowed Concentration | National Ambient Air Quality Standards Standards (NAAQS) | Secondary NAAQS or 90 percent of Primary, whichever is lowest | National Ambient Air Quality Standards |

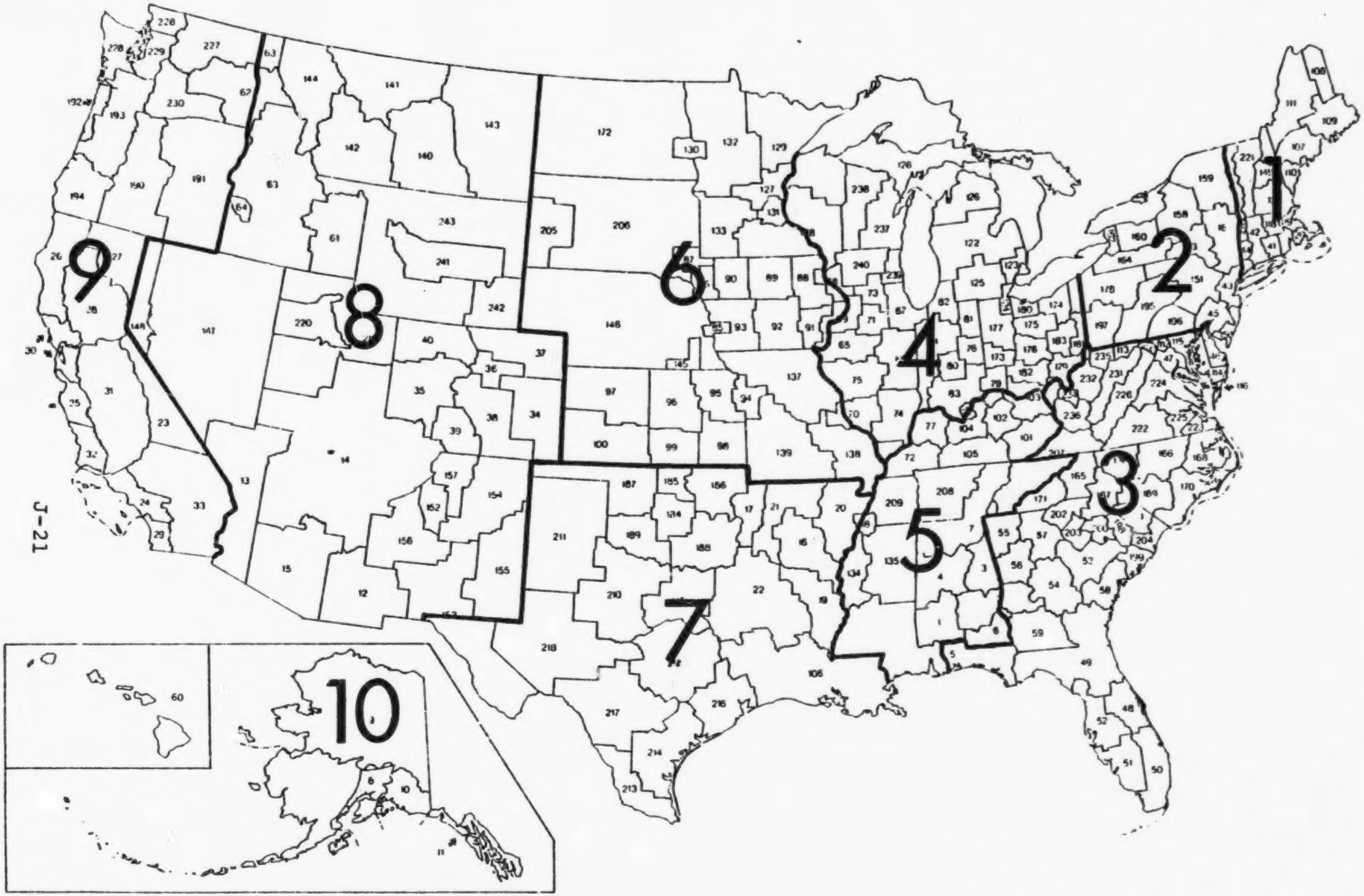
1
2
3
4
5
6
7
8
9
10

Figure J-14. Air Quality Control and Demand Regions.

Sulfur dioxide violation is not nearly as great a problem. Region 9 contains isolated problem areas as does Region 8. In Region 8, however, the AQCR's are so large that the several areas containing violations probably take on undue significance. The regions of greatest concern are those south of the Great Lakes, Regions 4 and 5.

Figure J-3 indicates that carbon monoxide violations tend to be highly dependent on there being significant urban activity in the AQCR. Region 9 apparently has the largest percentage of the Region affected. The Gulf Coast is also an area containing several violators.

Nitrogen dioxide violations are recorded in highly localized areas of all regions except Region 10. Oxidant violations depicted in Figure J-5 indicate that Regions 9, 7, 2 and 1 have a significant number of problem AQCR's.

Table J-4 summarizes the regional distribution of AQCR violations outlined above. Figure J-15 shows the location of all AQMA'a as they relate to the Demand Regions. Table J-5 displays the number of AQMA's in each of these regions with a breakdown according to each of the criteria pollutants.

Another aspect of regional air quality concerns the potential for episodes of meteorological conditions that are conducive to a degradation of air quality. Figure J-16 shows isopleths of the total number of days during a 5-year period when a high potential for air pollution was forecast.[4] The greatest number of forecast-days are found in Region 9, which ranges from less than 10 in the far north, to over 70 in central California, and back to nearly 20 days in the far south.

## 2. Water Supply and Usage

The freshwater supply in a region is dependent on rainfall. As can be seen from Figure J-17, the eastern half of the country generally has rainfall exceeding 30 to 40 inches. Figure J-18 which charts the flows of the major rivers in the United States shows that the eastern half of the country and the northwest have the highest stream flows. Although there

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[4] G.C. Holzworth, Mixing Heights, Wind Speeds, and Potential for Urban Air Pollution Throughout the Contiguous United States, EPA Office of Air Programs, Publication No. AP-101, January 1972.

## TABLE J-4

## SUMMARY OF DEGREE OF REGIONAL AQCR VIOLATIONS

| | DEMAND REGION | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
| PM: | S | M | S | M | M | M | M | M | M | S |
| $SO_2$ | L | S | S | M | S | L | L | S | L | N |
| CO | S | S | L | S | L | L | S | S | M | M |
| $NO_2$ | S | L | L | S | L | L | L | L | L | N |
| Ox | M | M | S | S | M | S | M | L | M | N |

M: Much of the region is made up of violated AQCR's.
S: Some of the region is made up of violated AQCR's.
L: Little of the region is made up of violated AQCR's.
N: None of the region is made up of violated AQCR's.

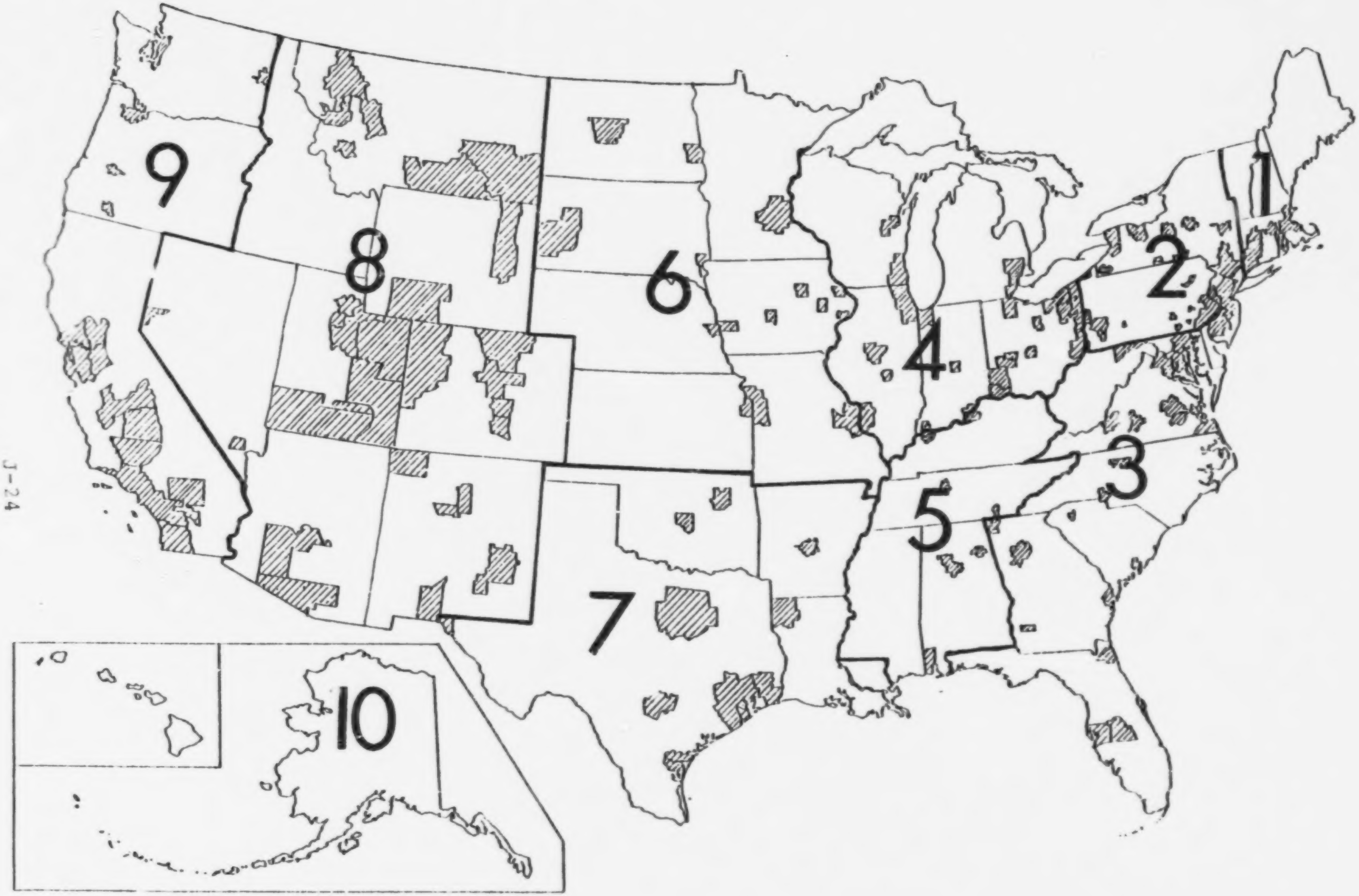

Figure J-15. Distribution of Air Quality Maintenance Areas in the United States showing Demand Region boundaries.

## TABLE J-5

## NUMBER OF DESIGNATED AQMA'S IN EACH DEMAND REGION FOR EACH CRITERIA POLLUTANT

| | DEMAND REGION | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
| PM | 6 | 27 | 23 | 21 | 8 | 16 | 9 | 26 | 13 | 0 |
| $SO_2$ | 3 | 9 | 5 | 13 | 1 | 3 | 1 | 12 | 4 | 0 |
| CO | 1 | 1 | 0 | 1 | 0 | 1 | 0 | 14 | 6 | 0 |
| $NO_2$ | 0 | 1 | 0 | 1 | 0 | 1 | 0 | 1 | 1 | 0 |
| Ox | 4 | 5 | 5 | 6 | 1 | 2 | 8 | 8 | 10 | 0 |

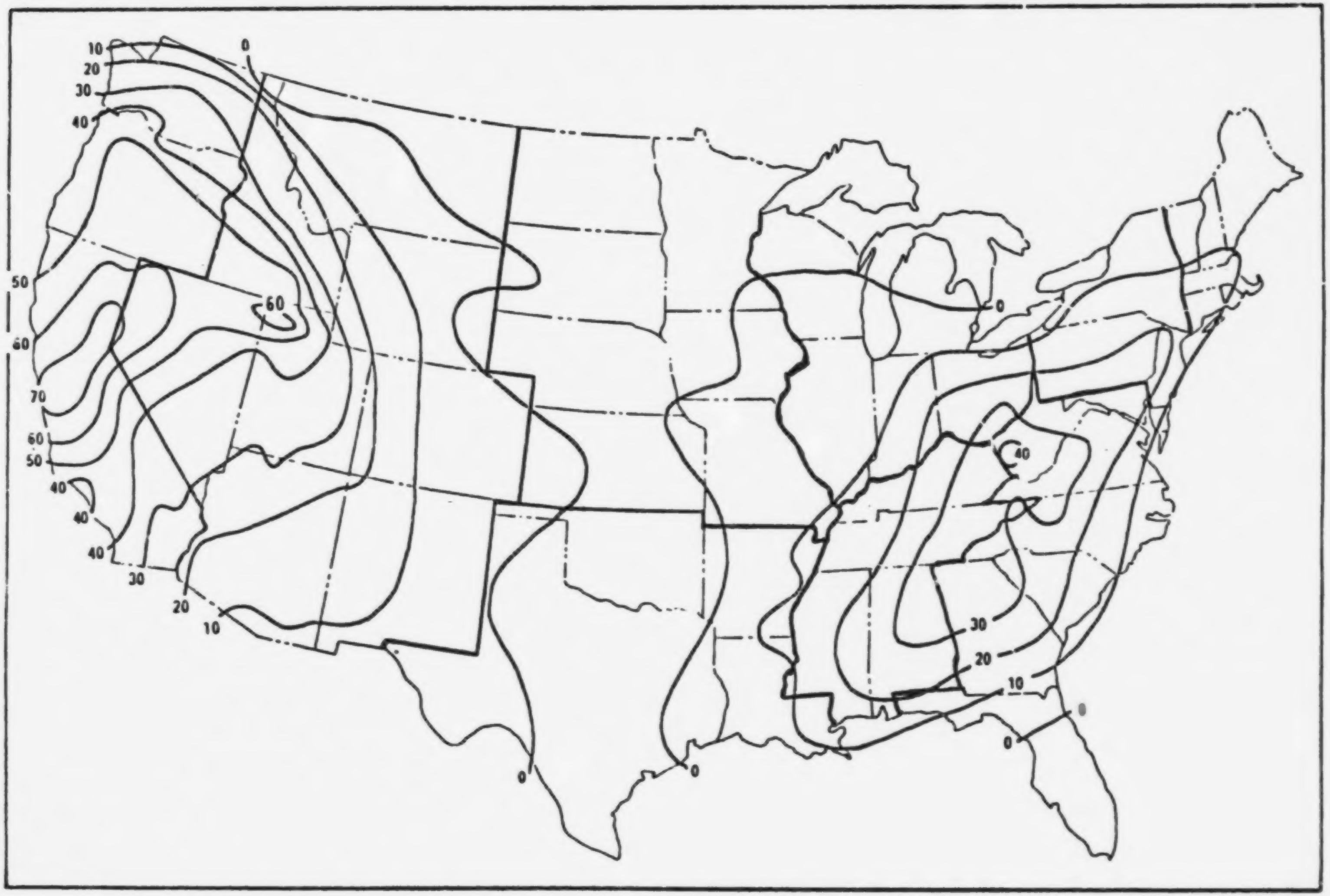
10
20
30
40
0
50
60
60
70
60
50
40
40
40
30
20
10
0
0
0
40
30
20
10
0
0

Figure J-16. Isopleths of total number of forecast-days of high meteorological potential for air pollution in a 5-year period. Data are based on forecasts issued starting August 1, 1960 and October 1, 1963 for eastern and western parts of the United States, respectively, through April 3, 1970. (G.C. Holzworth, Mixing Heights, Wind Speeds and Potential for Urban Air Pollution Throughout the Contiguous United States, EPA Office of Air Programs, Publication No. AP-101, January 1972.)

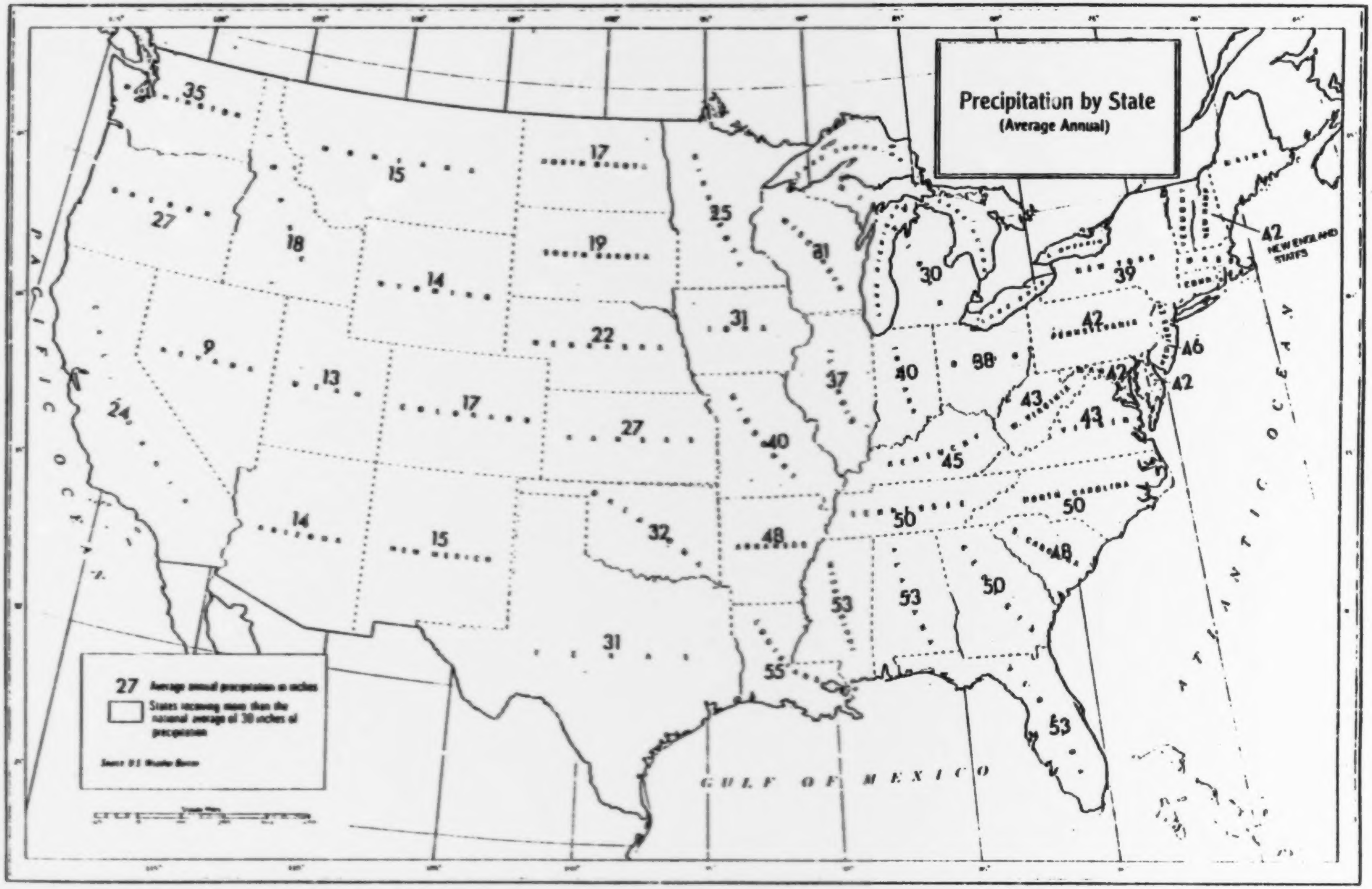
Precipitation by State
(Average Annual)
35
15
17
27
18
19
25
31
30
42
NEW ENGLAND STATES
39
14
22
31
42
46
9
13
17
27
37
40
38
43
42
24
40
45
43
42
14
15
32
48
50
NORTH CAROLINA
50
48
53
53
50
31
55
53
PACIFIC OCEAN
ATLANTIC OCEAN
GULF OF MEXICO
27 Average annual precipitation in inches
States receiving more than the national average of 30 inches of precipitation
Source: U.S. Weather Bureau

Figure J-17. Average annual precipitation by state. (Geraghty and Miller et al., Water Atlas of the United States, Plate 3.)

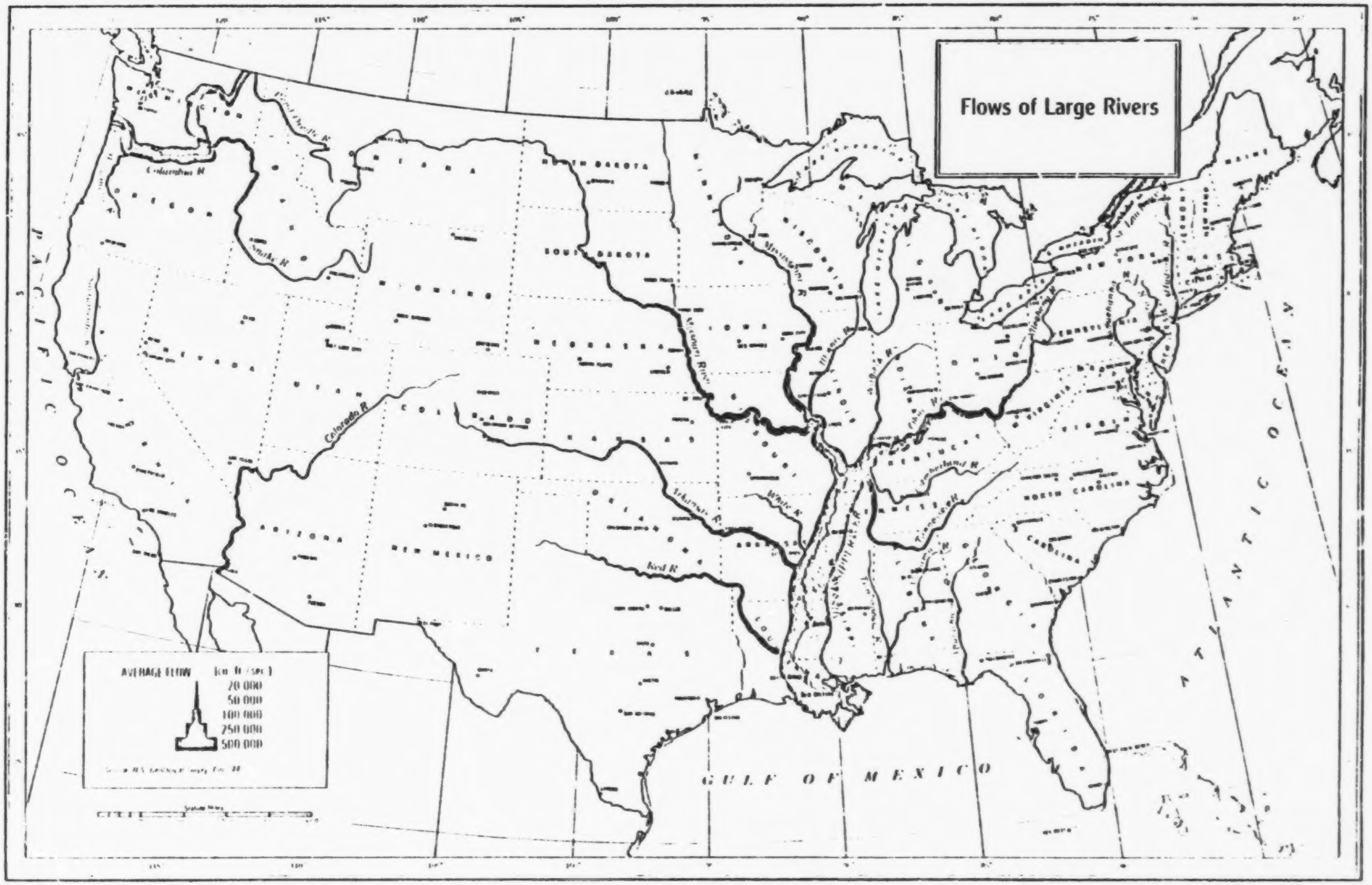
Flows of Large Rivers
AVERAGE FLOW (cu ft/sec)
20 000
50 000
100 000
250 000
500 000
Statute Miles
PACIFIC OCEAN
ATLANTIC OCEAN
GULF OF MEXICO
Colorado R
Missouri River
Arkansas R
Red R
White R
Ohio R
Cumberland R
Tennessee R
Mississippi R
Illinois R
Snake R
Columbia R
NEW MEXICO
ARIZONA
NORTH DAKOTA
SOUTH DAKOTA
NORTH CAROLINA

Figure J-18. Flows of large rivers. (Geraghty and Miller et al., Water Atlas of the United States, Plate 23.)

might be localized shortages because of high demand and lack of a convenient supply, the overall water picture for surface supplies in the eastern half of the country and Northwest is good. It should be emphasized that water cannot indiscriminately be drawn from a river or lake especially if the use it will be put to might diminish its quality.

The surface water deficient areas generally occur in the western half of the country. With the exception of the Northwest and areas in the Rockies the amount of rainfall is less than half that in the East. To counter the problems of lack of convenient surface supplies there are a number of major water diversion projects either in existence or proposed. Most of the transfers occur in Texas and California. The importance of water transfers is made evident by the fact that one out of every five persons in the western states is served by a water supply system that imports from a source 100 miles or more away.[5]

Groundwater use (Figure IV-8) as a percentage of total water use is greatest in the western half of the country. In many parts of the West, where irrigation is extensively practiced, it is generally more economical to obtain water supplies from wells than it is to construct facilities for importing water over large distances. Groundwater use is increasing in importance. The flow from ground water is obtained from tens of thousands of wells yielding anywhere from 25 to many thousands of gallons per minute. Major aquifers are shown in Figure J-19.

The breakdown by individual uses of water within Demand Regions is given in Table J-6. As can be seen from the table, industrial or agricultural uses of water predominate. Agricultural use of water is particularly significant in the Southwest and far West with California and Texas utilizing 33 and 10 billion gallons of water per day, respectively. The San Joaquin Valley of California and the northwest section of Texas are the two principal areas of those states under irrigation.

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[5] Geraghty and Miller et al., Water Atlas of the United States (Port Washington, New York: Water Information Center, 1973).

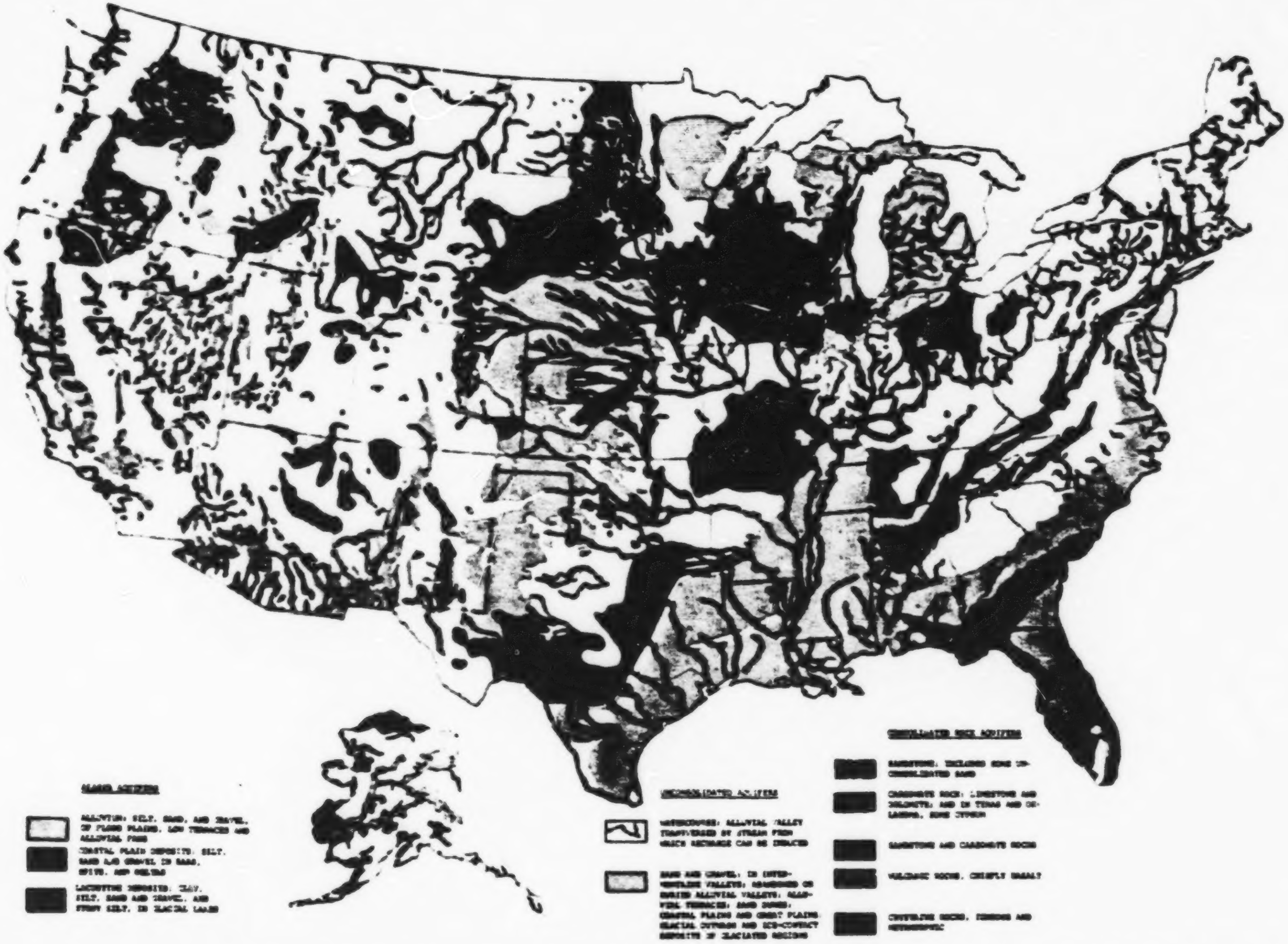
UNCONSOLIDATED AQUIFERS
CONSOLIDATED ROCK AQUIFERS
SANDSTONE AND CARBONATE ROCKS
VOLCANIC ROCKS, CHIEFLY BASALT

Figure J-19. Productive aquifers and withdrawals from wells. (U.S. Geological Survey. The National Atlas of the United States, Washington, D.C. 1970, p. 122-123.)

Note: A color copy of this diagram is available for viewing at the FEA Freedom of Information Office in Washington, D.C.

## TABLE J-6

## DAILY WATER USAGE

(MGD)

| REGION | TOTAL WATER USAGE | PUBLIC WATER SUPPLIES | WITHDRAWAL OF WATER FOR INDUSTRY | WITHDRAWAL OF WATER FOR RURAL USE[1] | WITHDRAWAL OF WATER FOR IRRIGATION |
|---|---|---|---|---|---|
| 1 | 9,756 | 1,432 | 8,120 | 123 | 81 |
| 2 | 42,585 | 3,900 | 38,200 | 372 | 113 |
| 3 | 48,820 | 3,406 | 42,300 | 710 | 2,404 |
| 4 | 61,127 | 5,670 | 54,600 | 670 | 187 |
| 5 | 19,570 | 1,150 | 17,700 | 321 | 399 |
| 6 | 19,645 | 1,650 | 8,850 | 902 | 8,243 |
| 7 | 40,282 | 2,210 | 23,860 | 492 | 13,720 |
| 8 | 57,480 | 1,390 | 2,050 | 340 | 53,700 |
| 9 | 62,653 | 4,680 | 12,600 | 692 | 44,681 |
| 10 (Alaska) | 275 | 60 | 200 | 15 | 0 |
| TOTAL | 362,193 | 25,548 | 208,480 | 4,637 | 123,528 |
| PERCENTAGE OF TOTAL | | 7 | 58 | 1 | 34 |

---

[1] Not served by public systems. Measures withdrawal from private sources of water such as wells.

### 3. Water Quality

The maps in this section are from the Water Atlas of the United States[6] and were selected to provide a general picture of water quality at the national and regional level. Figure J-20 gives principal areas of surface water pollution. Figures J-21 and J-22 show groundwater hardness and deep-well injection disposal regulations respectively. The most direct impacts of oil production result from the consumption and contamination of groundwater supplies and the disposal of produced brines. Hardness renders ground water less useful in injection technologies. Thermal pollution (Figure J-23) is a less direct impact stemming from refining and power generation. Pipeline breakage (Figure J-24) can be very detrimental to surface supplies and debilitate treatment facilities.

Surface water pollution in the West South Central Region is predominant in the Cimarron, Canadian, Washington and Trinity River basins and extensive throughout the rest of the region excepting the White River drainage, which is slightly polluted. The Houston ship canal is one of the "ten dirtiest waterways." The groundwater supplies are relatively soft in Louisiana, Arkansas and East Texas, becoming increasingly hard in West Texas and Oklahoma. Texas has regulations restricting deep-well injection disposal. Thermal pollution is minor to moderate throughout the region, Texas being mostly moderate. Oil pipeline spills are a major problem, 139 taking place in 1969 in Texas alone.

Northeastern New Mexico, eastern Colorado and the Snake River Basin in Idaho exhibit predominant surface water pollution. The remainder of the Mountain Region is extensively to moderately polluted. Groundwater supplies are extremely hard in southeastern New Mexico, northeastern Colorado, eastern Wyoming, Arizona and Nevada. South central Wyoming, central Colorado and central New Mexico are moderately hard, with the remainder being classified as hard. There are no special deep-well disposal regulations in the region. Thermal pollution is a major problem in Idaho and western Wyoming and Montana, moderate throughout the rest of Montana and much of Wyoming and minor elsewhere in the region. Pipeline spills are moderate sources of contamination in New Mexico and Wyoming and minor elsewhere.

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[6] Geraghty and Miller et al., Water Atlas of the United States.

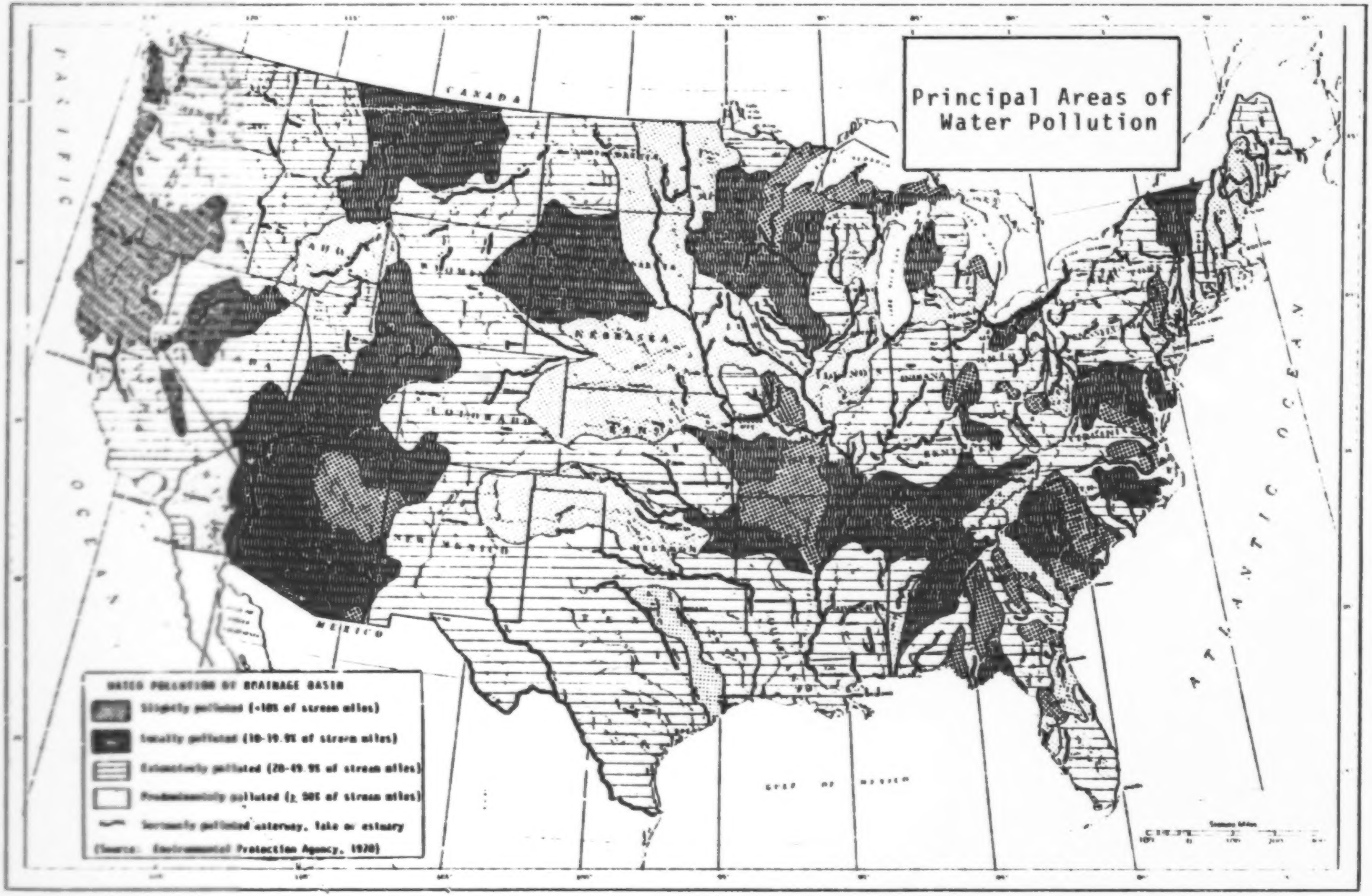
Principal Areas of Water Pollution
PACIFIC OCEAN
CANADA
NEBRASKA
COLORADO
MEXICO
ATLANTIC OCEAN
GULF OF MEXICO
WATER POLLUTION OF DRAINAGE BASIN
Slightly polluted (<10% of stream miles)
Locally polluted (10-19.9% of stream miles)
Extensively polluted (20-49.9% of stream miles)
Predominantly polluted (≥ 50% of stream miles)
Seriously polluted waterway, lake or estuary
(Source: Environmental Protection Agency, 1970)

Figure J-20. Surface water pollution. (Geraghty and Miller et al., Water Atlas of the United States, Plate 51.)

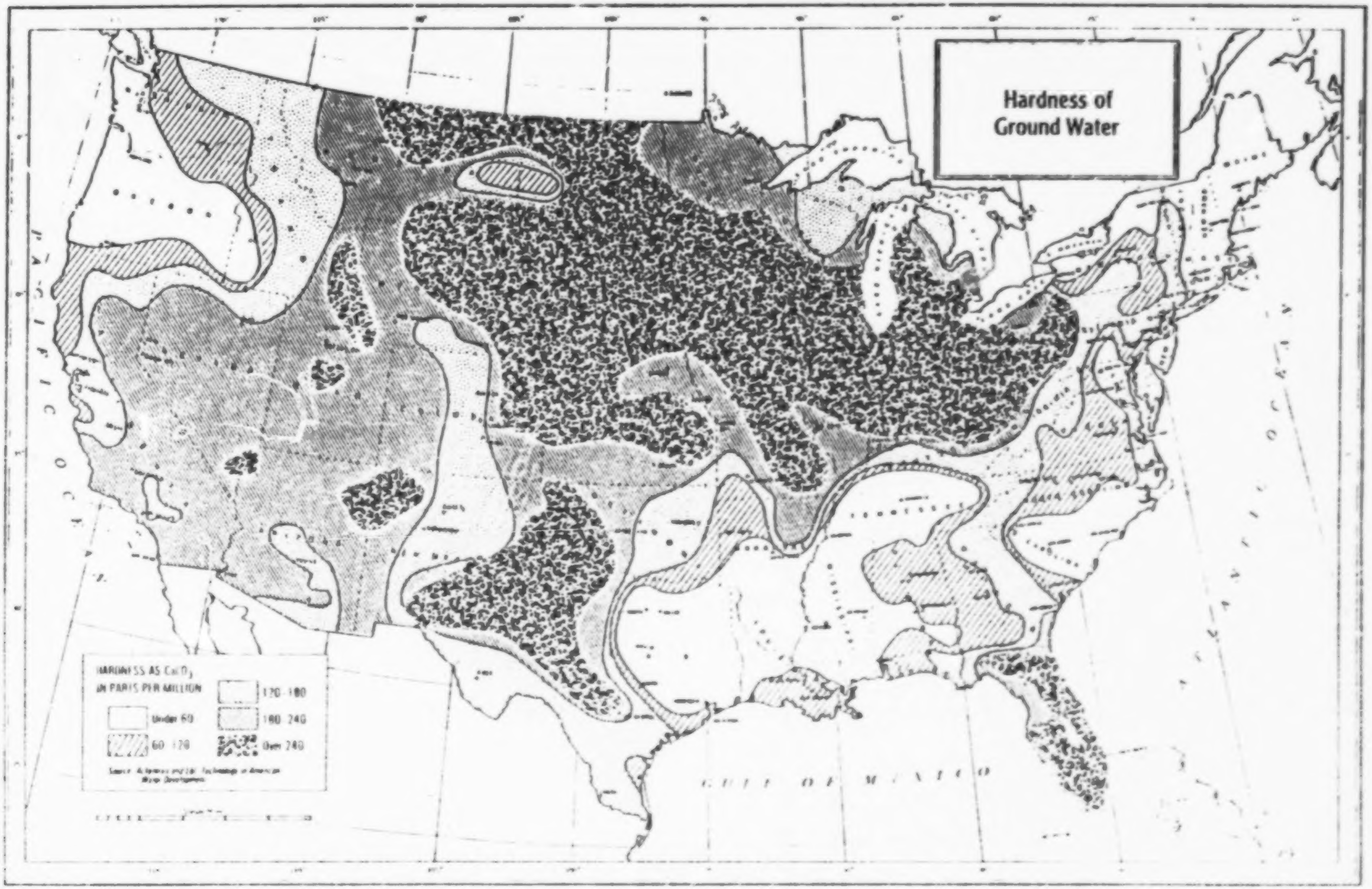
Hardness of Ground Water
PACIFIC OCEAN
ATLANTIC OCEAN
GULF OF MEXICO
HARDNESS AS $CaCO_3$ IN PARTS PER MILLION
Under 60
60 - 120
120 - 180
180 - 240
Over 240

Figure J-21. Hardness of ground water. (Geraghty and Miller et al., Water Atlas of the United States, Plate 42.)

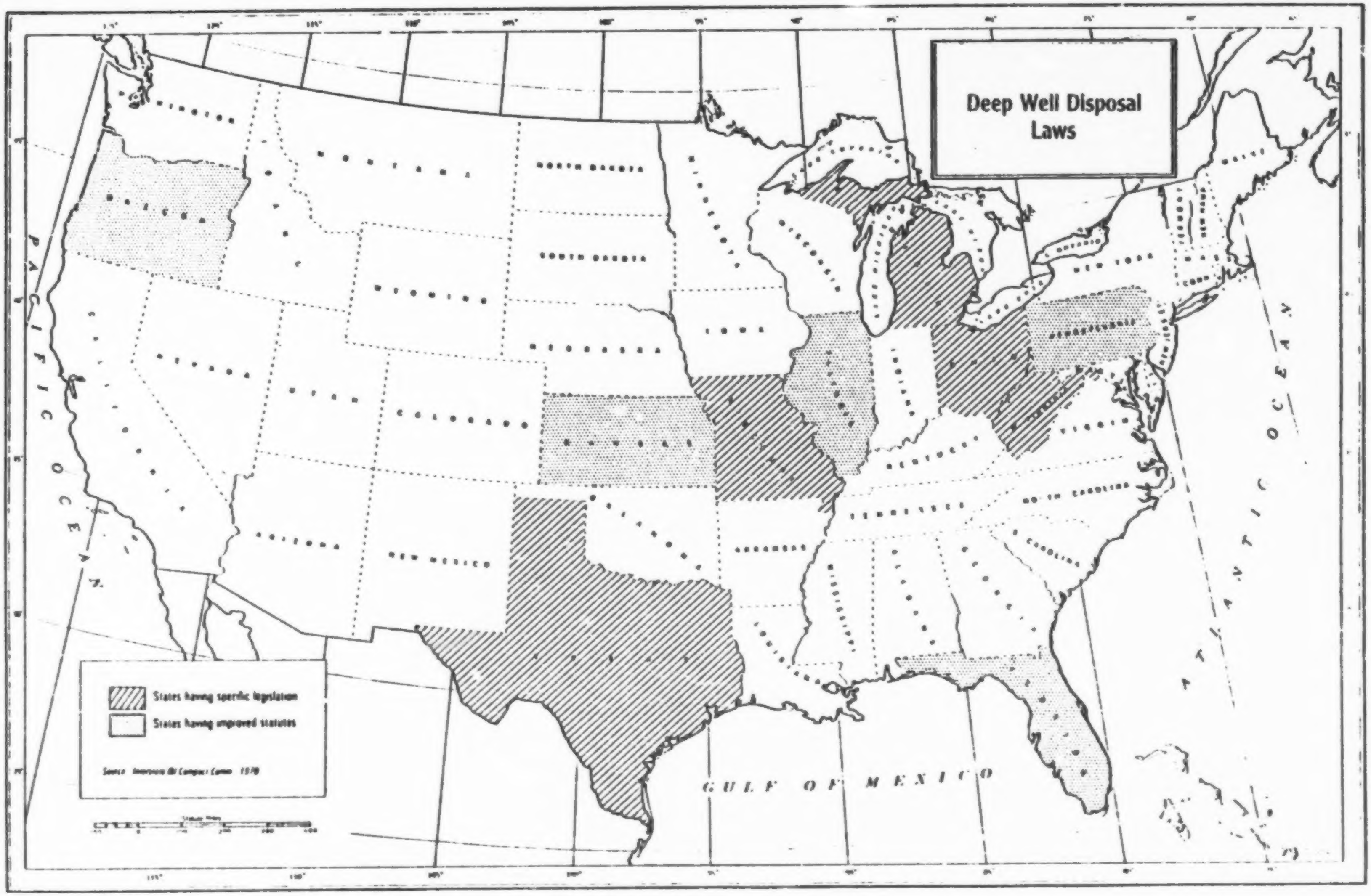
Deep Well Disposal Laws
PACIFIC OCEAN
ATLANTIC OCEAN
GULF OF MEXICO
States having specific legislation
States having improved statutes
Source: Interstate Oil Compact Comm. 1970

Figure J-22. Deep well disposal laws. (Geraghty and Miller et al., Water Atlas of the United States, Plate 36.)

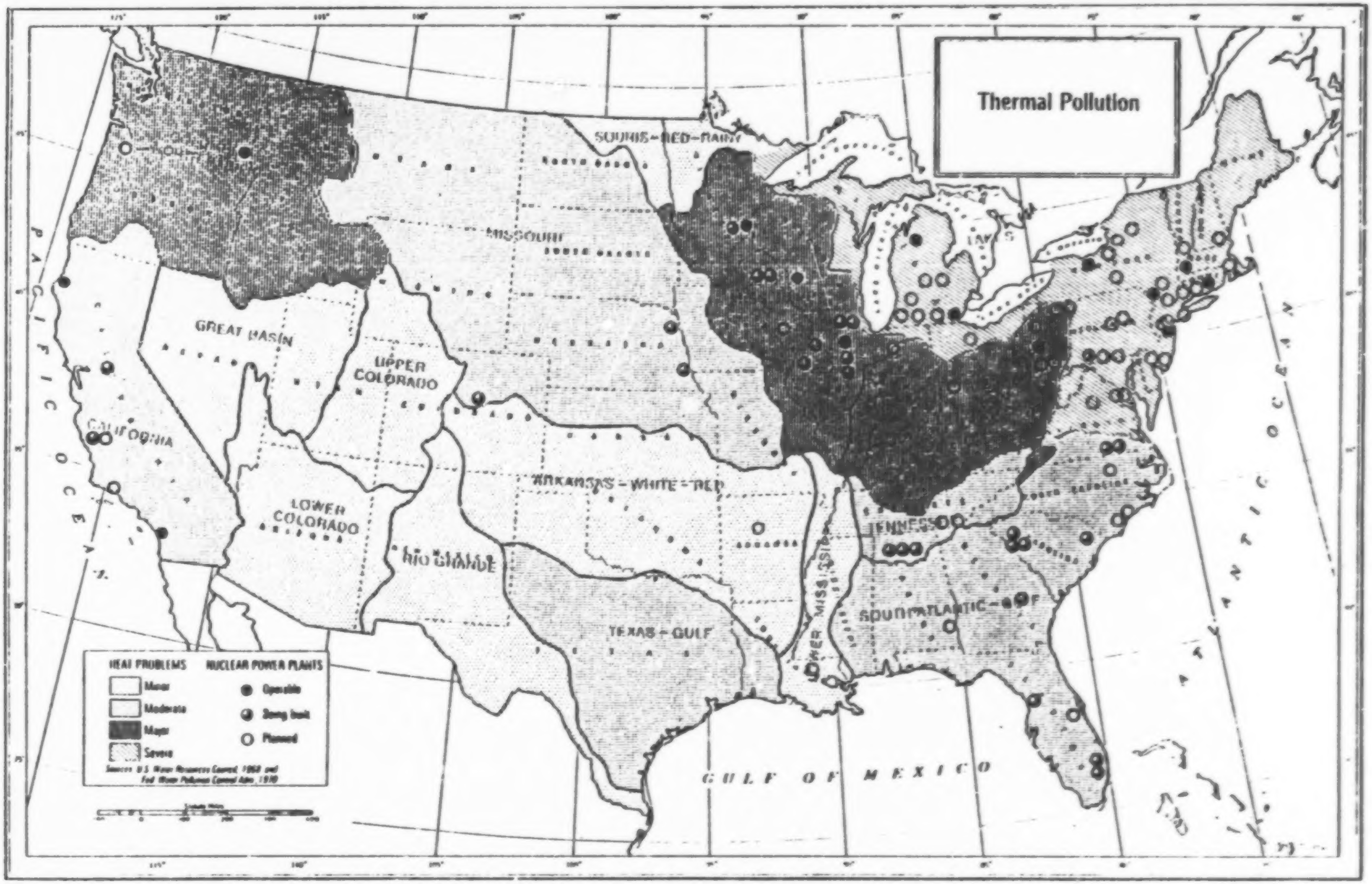
Thermal Pollution
SOURIS-RED-RAINY
MISSOURI
GREAT BASIN
UPPER COLORADO
CALIFORNIA
LOWER COLORADO
RIO GRANDE
ARKANSAS-WHITE-RED
TEXAS-GULF
LOWER MISSISSIPPI
TENNESSEE
SOUTH ATLANTIC-GULF
LAKES
PACIFIC OCEAN
ATLANTIC OCEAN
GULF OF MEXICO
HEAT PROBLEMS
Minor
Moderate
Major
Severe
NUCLEAR POWER PLANTS
Operable
Being built
Planned
Sources: U.S. Water Resources Council, 1968 and Fed. Water Pollution Control Adm., 1970

Figure J-23. Thermal pollution. (Geraghty and Miller et al., Water Atlas of the United States, Plate 58.)

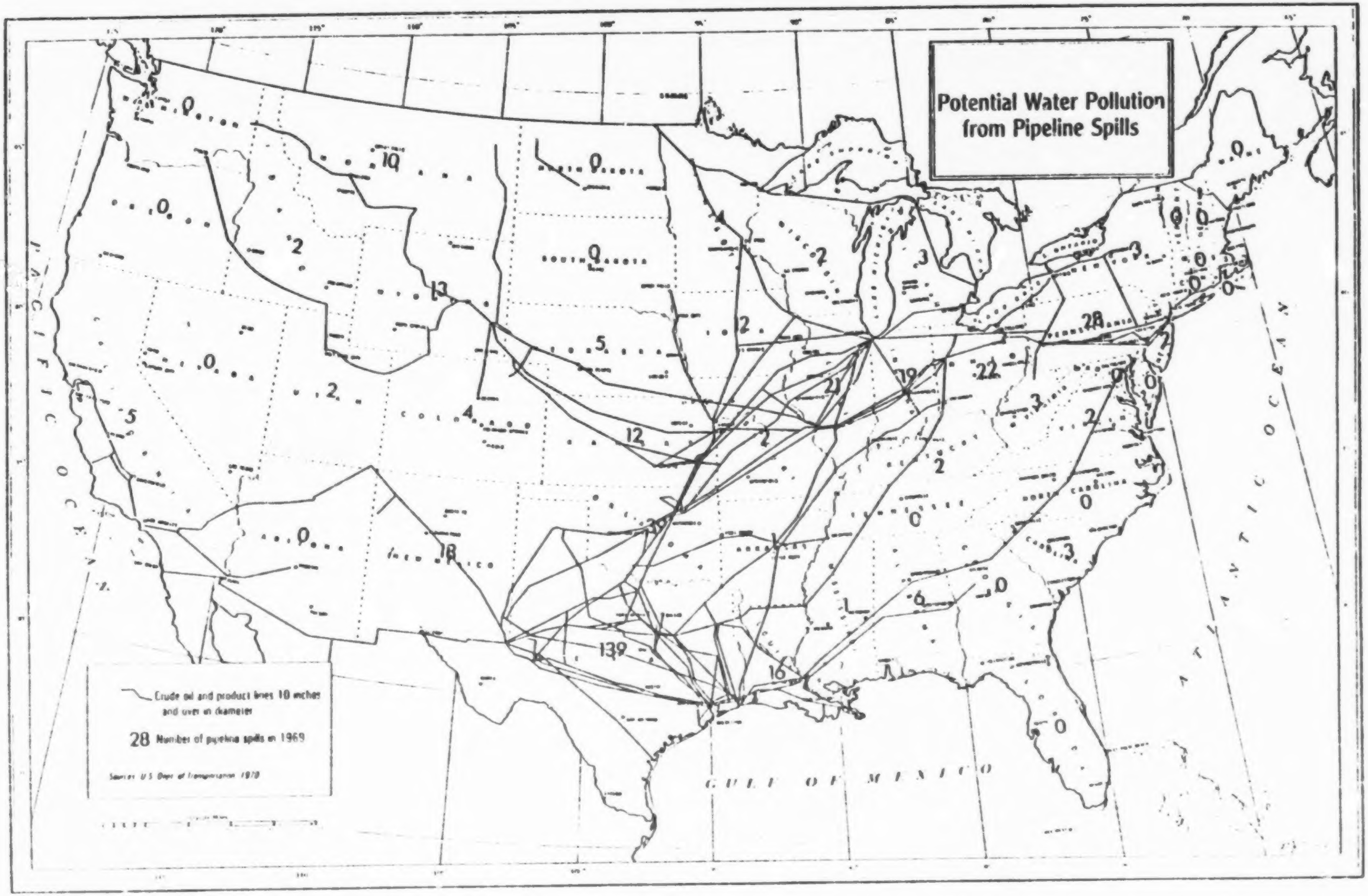
Potential Water Pollution from Pipeline Spills
PACIFIC OCEAN
ATLANTIC OCEAN
GULF OF MEXICO
0
10
0
0
2
0
13
12
2
3
0
0
0
3
0
0
0
28
5
0
2
4
5
21
19
22
12
2
3
0
0
2
2
0
0
0
18
3
0
6
139
16
0
Crude oil and product lines 10 inches and over in diameter
28 Number of pipeline spills in 1969
Source: U.S. Dept of Transportation 1970

Figure J-24. Potential water pollution from pipeline spills. (Geraghty and Miller et al., Water Atlas of the United States, Plate 62.)

Southern California surrounding and north of the Salton Sea area exhibits predominant surface water pollution; pollution is extensive to predominant up the coast to San Francisco and mostly localized north of California along the coast. Inland it is generally extensive. Groundwater supplies are hard in Southern California and range to moderate and soft in Oregon and Washington. Oregon is the only state with statutes regulating deep-well injection disposal. Thermal pollution is a major problem in Washington and Oregon and a moderate problem in California. Oil pipeline spills are a minor problem in this region.

### 4. Major Biomes and Land Use

Figures J-25 and J-26 indicate major biomes and land use in the United States. The biomes vary significantly according to temperature, rainfall, wind patterns, substrate, terrain, etc. from north to south and east to west, from dense forests to vast deserts, from coastal wetlands to alpine habitats. Between the mountain ranges are the lowlands that support most of the agriculture of the country, much forest land and the deserts. Most of the urban areas and industry are located along the coastal regions and around the Great Lakes. The temperate climate of the Gulf Coast is primarily influenced by the warm and gently moving Gulf waters and the Mississippi River. The coastal areas in the East are also significantly influenced by the mild waters of the Gulf Stream. The western coastal areas, on the other hand, are dominated by the cool Arctic currents. Most of the coastal influences are checked by major north-south running mountain ranges. A brief description of the characteristics of some of the Demand Regions follows.

The heterogeneous West South Central Region is characterized in the western expanse by semi-arid shrubland, pinon-juniper chaparral and grassland. Moving eastward, mixed forests appear and merge into pine and cypress-gum floodplain forests. Marshes and mudflats stretch along the coastal plain. With 70 percent of the available land utilized in agriculture, this region supports cotton, oat, soybean, rice, sweet potato, sugar cane, poultry and livestock farming. Parks and protected lands constitute less than 1 percent of the total area. Urban areas are linked to the southern Gulf Coast.

The northern sections of the Mountain Region are typified by great pine and Douglas fir forests and sagebrush steppes. Eastward, pasture and grasslands continue. The central and southern regions host the major U.S. desert area, where endemic vegetation includes creosote, saltbush,

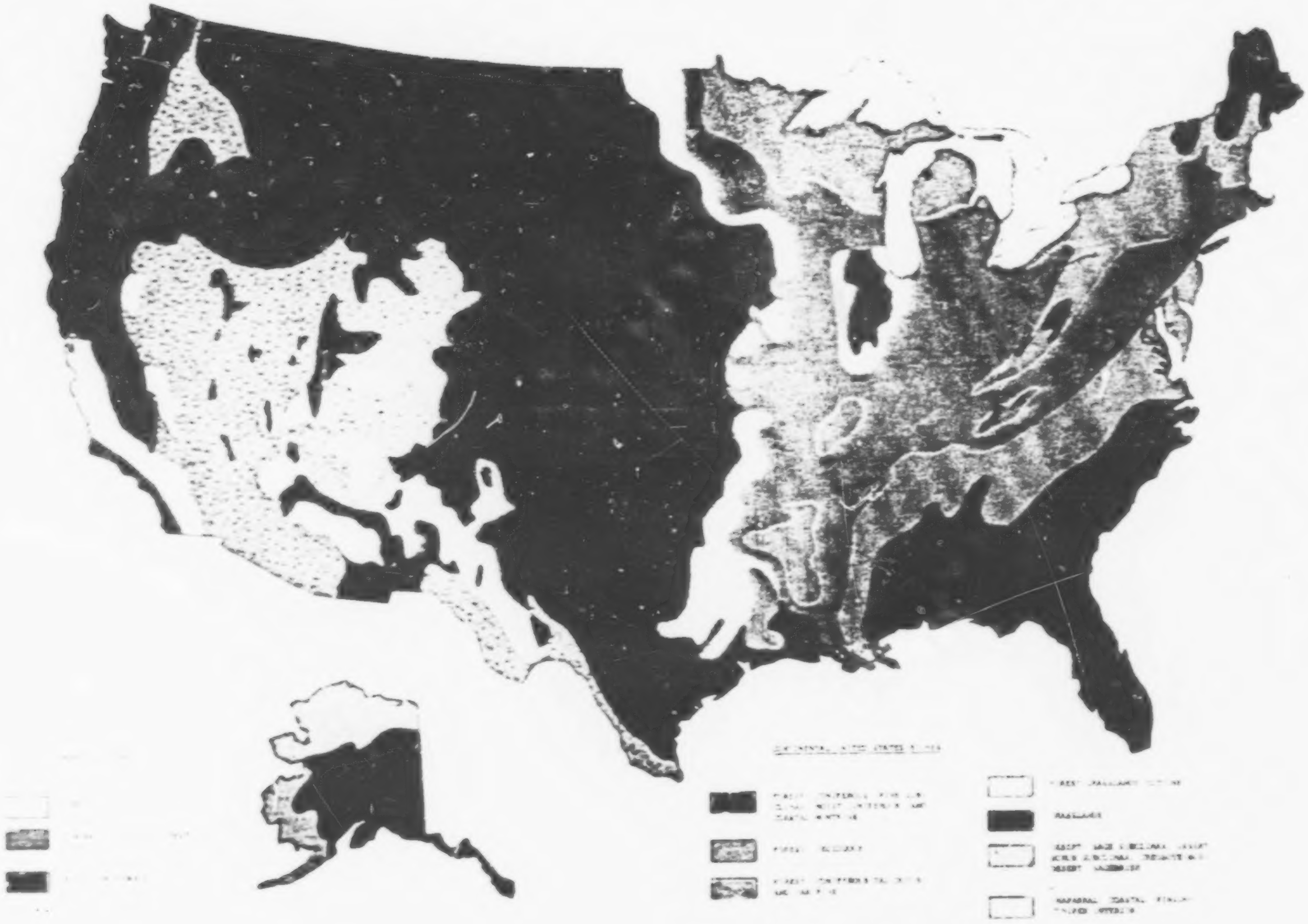
CONTINENTAL UNITED STATES BIOMES
GRASSLAND

Figure J-27. Major Biomes of the United States.

Note: A color copy of this diagram is available for viewing at the FAA Freedom of Information Office in Washington, D.C.

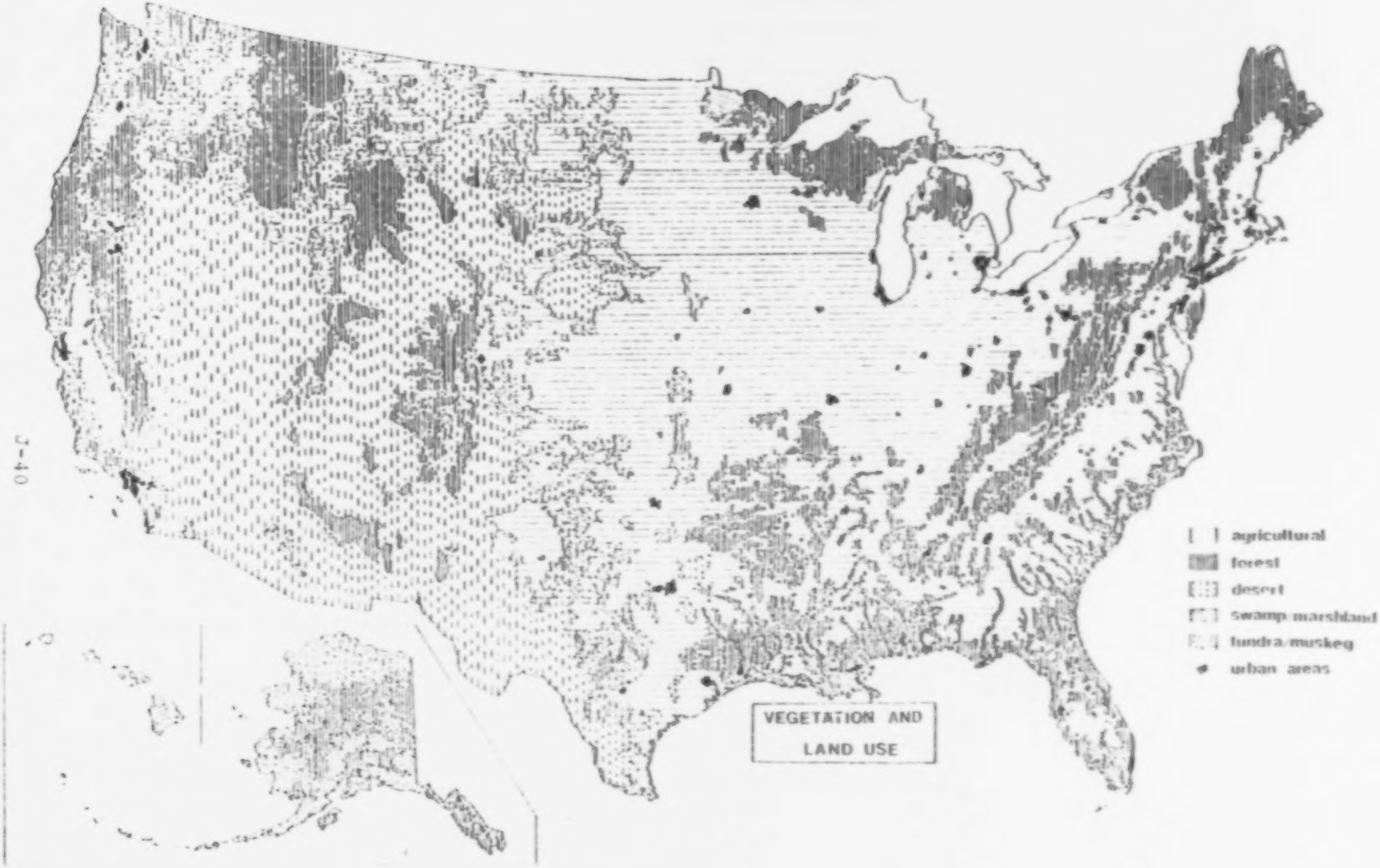
agricultural
forest
desert
swamp-marshland
tundra/muskeg
urban areas
VEGETATION AND LAND USE

Figure J-26. Vegetation and land use in the United States.

sagebrush and piñon-juniper chaparral. Farm yields are predominantly dry field crops such as alfalfa and wild hay. Most of the remaining productive land is used for livestock grazing. The region's 13 National Parks employ 2.1 percent of the total area.

The expanse of Douglas fir, spruce and pine forest dominates the coastal Pacific Region. Across the Northwest sagebrush and grassland continue, while coastal chaparral stretches down Central California. The coast is steep and high cliffed. Rocky, sandy and pocket beaches are all distinguishable. Agriculturally-developed land constitutes 35 percent of the total area and is responsible for the production of vegetables, fruit, nuts, barley, winter wheat, alfalfa, sugar beets and dairy goods. With eight National Parks, protected lands incorporate 2.2 percent of the region. Urban settlements are linked to the coast or situated in the Valley.

### 5. Socioeconomic

The population of the United States was 211,390,000 in 1974. In the labor force were 92,349,000, with an unemployment rate of 4.7 percent. This rate had climbed to 8.6 percent by April 1975. Employed in petroleum and gas extraction and refining were 341,000 persons or 0.37 percent of the labor force.

Table J-7 gives a summary of U.S. energy use from 1964 to 1973. Note that in 1973, 17.9 percent of the energy came from coal, 42.3 percent from petroleum and 34.8 percent from natural gas. Table J-8 gives a summary of U.S. energy production. More recent figures show that U.S. production of crude petroleum fell to about 8,700 million barrels per day in 1974, and 8,300 million in 1975. Petroleum demand fell by 4 percent in 1974 and 2.5 percent in 1975, due partially to higher prices, but mainly to the recession.

Table J-9 presents some energy facts for the United States, broken down by Demand Region. Total highway gasoline use for 1973 was 2,433 million barrels,[7] while all other uses totalled 3,310 million barrels in 1974.[8] About 12

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[7] Bureau of Mines, Sales of Fuel Oil and Kerosine in 1974, and Bureau of Mines, Petroleum Statement, 1974, Table 16.

[8] World Almanac, 1975, Motor Fuel Consumption (Highway).

## TABLE J-7

## CALCULATED CONSUMPTION OF MINERAL ENERGY RESOURCES AND ELECTRICITY FROM HYDROPOWER AND NUCLEAR POWER IN THE UNITED STATES
## (DAILY AVERAGES)

| | 1964 | 1965 | 1966 | 1967 | 1968 | 1969 | 1970 | 1971 | 1972 | 1973[2] |
|---|---|---|---|---|---|---|---|---|---|---|
| Bituminous Coal and Lignite (1,000 net tons) | 1,178 | 1,258 | 1,332 | 1,316 | 1,363 | 1,390 | 1,413 | 1,356 | 1,420 | 1,543 |
| Anthracite Coal (1,000 net tone) | 39 | 35 | 31 | 30 | 28 | 24 | 23 | 20 | 16 | 15 |
| Petroleum Products: (1,000 barrels) | | | | | | | | | | |
| From crude petroleum | 8,829 | 9,066 | 9,467 | 9,836 | 10,318 | 10,661 | 10,909 | 11,188 | 11,690 | 12,440 |
| From other sources[1] | 866 | 1,239 | 1,340 | 1,381 | 1,602 | 1,840 | 2,116 | 2,349 | 2,848 | 2,970 |
| Natural Gas, dry (million cu. ft.) | 41,077 | 42,735 | 46,174 | 48,451 | 51,839 | 55,857 | 58,540 | 60,637 | 61,283 | 62,603 |
| Natural Gas Liquids (1,000 barrels) | 1,147 | 1,207 | 1,277 | 1,343 | 1,473 | 1,635 | 1,665 | 1,676 | 1,826 | 1,843 |
| Electricity: (MM KWH) | | | | | | | | | | |
| Water Power | 493 | 529 | 545 | 615 | 615 | 697 | 692 | 748 | 776 | 776 |
| Net E - Exports | – | – | – | 1 | 2 | – | – | – | – | – |
| Net I - Imports | 5 | – | 3 | – | – | 3 | 5 | 10 | 21 | 19 |
| Nuclear | 9 | 10 | 15 | 21 | 34 | 38 | 60 | 104 | 148 | 219 |

### CALCULATED CONSUMPTION IN BRITISH THERMAL UNITS
### (DAILY AVERAGES IN TRILLIONS OF B t u.)

| | 1964 | 1965 | 1966 | 1967 | 1968 | 1969 | 1970 | 1971 | 1972 | 1973[2] |
|---|---|---|---|---|---|---|---|---|---|---|
| Bituminous Coal and Lignite | 31 | 32 | 33 | 33 | 34 | 34 | 34 | 32 | 34 | 37 |
| Anthracite Coal | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | - |
| Petroleum Products: | | | | | | | | | | |
| From crude petroleum | 51 | 51 | 53 | 55 | 58 | 60 | 61 | 63 | 65 | 69 |
| From other sources[1] | 6 | 8 | 8 | 9 | 10 | 11 | 13 | 14 | 17 | 18 |
| Natural Gas, dry | 42 | 44 | 48 | 50 | 54 | 58 | 60 | 62 | 63 | 65 |
| Natural Gas Liquids | 5 | 5 | 6 | 6 | 6 | 7 | 7 | 7 | 7 | 7 |
| Electricity | | | | | | | | | | |
| Water Power | 5 | 5 | 6 | 6 | 6 | 7 | 7 | 8 | 8 | 8 |
| Nuclear | – | – | – | – | – | – | 1 | 1 | 2 | 3 |
| Total | 141 | 146 | 155 | 160 | 169 | 178 | 184 | 188 | 197 | 207 |

### CALCULATED CONSUMPTION IN BRITISH THERMAL UNITS
### (PER CENT OF TOTAL)

| | 1964 | 1965 | 1966 | 1967 | 1968 | 1969 | 1970 | 1971 | 1972 | 1973[2] |
|---|---|---|---|---|---|---|---|---|---|---|
| Bituminous Coal and Lignite | 21.8 | 21.7 | 21.6 | 20.6 | 20.1 | 19.3 | 18.6 | 17.3 | 17.1 | 17.7 |
| Anthracite Coal | .7 | .6 | .5 | .5 | .4 | .3 | .3 | .3 | .2 | .2 |
| Petroleum Products: | | | | | | | | | | |
| From crude petroleum | 36.1 | 34.7 | 34.2 | 34.7 | 34.2 | 33.5 | 33.3 | 33.4 | 33.2 | 33.6 |
| From other sources[1] | 3.8 | 5.4 | 5.5 | 5.3 | 6.0 | 6.4 | 7.0 | 7.4 | 8.7 | 8.7 |
| Natural Gas, dry | 30.5 | 30.2 | 30.9 | 31.3 | 31.7 | 32.4 | 32.8 | 33.2 | 32.1 | 31.2 |
| Natural Gas Liquids | 3.4 | 3.5 | 3.5 | 3.5 | 3.6 | 3.8 | 3.7 | 3.6 | 3.8 | 3.6 |
| Electricity: | | | | | | | | | | |
| Water Power | 3.6 | 3.8 | 3.7 | 4.0 | 3.8 | 4.1 | 4.0 | 4.2 | 4.1 | 3.9 |
| Nuclear | .1 | .1 | .1 | .1 | .2 | .2 | .3 | .6 | .8 | 1.1 |
| Total | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 |

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[1] Includes imports, exports, processing gains, and stock change.

[2] Preliminary.

Source: Bureau of Mines, Petroleum Statement, December and Annual issues.

# TABLE J-8

## PRODUCTION OF MINERAL ENERGY RESOURCES AND ELECTRICITY FROM HYDROPOWER AND NUCLEAR POWER IN THE UNITED STATES (DAILY AVERAGES)

| | 1964 | 1965 | 1966 | 1967 | 1968 | 1969 | 1970 | 1971 | 1972 | 1973[2] |
|---|---|---|---|---|---|---|---|---|---|---|
| Bituminous Coal and Lignite (1,000 net tons) . . . | 1,331 | 1,403 | 1,463 | 1,514 | 1,490 | 1,536 | 1,652 | 1,513 | 1,627 | 1,616 |
| Anthracite Coal (1,000 net tons) . . . | 47 | 41 | 35 | 34 | 31 | 29 | 27 | 24 | 19 | 18 |
| Crude Petroleum[1] (1,000 barrels) . . . | 7,614 | 7,804 | 8,295 | 8,810 | 9,096 | 9,238 | 9,637 | 9,463 | 9,441 | 9,187 |
| N tural Gas, wet lion cu. ft.) . . . | 42,246 | 43,945 | 47,141 | 49,794 | 52,793 | 56,708 | 60,057 | 61,625 | 61,562 | 62,740 |
| Electricity: (MM KWH) | | | | | | | | | | |
| Water Power . . . . | 493 | 540 | 542 | 616 | 617 | 694 | 687 | 739 | 754 | 757 |
| Nuclear . . . . . . . | 9 | 10 | 15 | 21 | 34 | 38 | 50 | 104 | 148 | 219 |
| **PRODUCTION IN BRITISH THERMAL UNITS (DAILY AVERAGES IN TRILLIONS OF B.t.u.)** | | | | | | | | | | |
| Bituminous Coal and Lignite . . . . . . . | 35 | 35 | 37 | 38 | 37 | 38 | 41 | 36 | 39 | 39 |
| Anthracite Coal . . | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| Crude Petroleum[1] . . | 44 | 44 | 46 | 50 | 51 | 52 | 54 | 53 | 53 | 51 |
| Natural Gas, wet (unprocessed) . . . . | 47 | 48 | 52 | 55 | 59 | 63 | 66 | 68 | 68 | 69 |
| Electricity | | | | | | | | | | |
| Water Power . . . . | 5 | 6 | 6 | 6 | 7 | 7 | 7 | 8 | 8 | 8 |
| Nuclear . . . . . . . | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 1 | 2 |
| Total . . . . . . . . | 132 | 134 | 142 | 150 | 155 | 161 | 169 | 167 | 170 | 170 |
| **PRODUCTION IN BRITISH THERMAL UNITS (Per Cent of Total)** | | | | | | | | | | |
| Bituminous Coal and Lignite . . . . . . | 26.4 | 26.5 | 26.1 | 25.4 | 24.2 | 23.8 | 24.0 | 22.0 | 23.0 | 22.9 |
| Anthracite Coal . . . | .9 | .8 | .6 | .6 | .5 | .4 | .4 | .4 | .3 | .3 |
| Crude Petroleum[1] | 33.5 | 32.4 | 32.6 | 33.2 | 32.8 | 32.2 | 32.0 | 31.7 | 31.1 | 30.2 |
| Natural Gas, wet (unprocessed) . . . . | 35.2 | 36.0 | 36.6 | 36.6 | 38.1 | 38.9 | 39.0 | 40.7 | 40.0 | 40.6 |
| Electricity | | | | | | | | | | |
| Water Power . . . | 3.9 | 4.2 | 4.0 | 4.1 | 4.2 | 4.5 | 4.2 | 4.6 | 4.6 | 4.6 |
| Nuclear . . . . . . . | .1 | .1 | .1 | .1 | .2 | .2 | .4 | .5 | 1.0 | 1.4 |
| Total . . . . . . . . | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 |

[1] Includes lease condensate.
[2] Preliminary.

Source: Bureau of Mines, Petroleum Statement, December and Annual issues.

# TABLE J-9

## REGIONAL ENERGY FACTS FOR THE UNITED STATES

| | REGION 1 | REGION 2 | REGION 3 | REGION 4 | REGION 5 | REGION 6 | REGION 7 | REGION 8 | REGION 9 | REGION 10 | TOTAL U.S. |
|---|---|---|---|---|---|---|---|---|---|---|---|
| (THOUSANDS) POPULATION, 1974 | 12,150 | 37,276 | 33,206 | 40,862 | 13,387 | 16,682 | 20,584 | 9,411 | 27,496 | 233 | 21[illegible],390 |
| (THOUSANDS) LABOR FORCE, 1974 | 5,449 | 15,844 | 15,380 | 18,079 | 5,603 | 7,401 | 8,509 | 4,018 | 11,940 | 146 | 92,389 |
| % UNEMPLOYMENT[1] | 7.1% | 6.2% | 4.6% | 5.7% | 4.3% | 4.2% | 4.7% | 5.3% | 7.6% | 10.2% | 5.7% |
| COAL MINING [2] | | | | | | | | | | | |
| EMPLOYMENT(1,000) | | 30.8 | 61.9 | 25.1 | 32.9 | 2.3 | 1.0 | OVER 2500 | 250-499 | 150-249 | 159.6 |
| WAGES IN MILLIONS OF $ | | 334.9 | 675.2 | 309.7 | 354.7 | 23.7 | 11.9 | (D) | (D) | (D) | 1777 |
| OIL&GAS EXTRACTION[2] | | | | | | | | | | | |
| EMPLOYMENT(1,000) | | OVER 2500 | 4.2 | 9.3 | 7.6 | 9.8 | 161.0 | 22.8 | 18.3 | 2.4 | 240.6 |
| WAGES IN MILLIONS OF $ | | (D)[4] | 40.2 | 80.6 | 63.1 | 86.0 | 1707.6 | 235.9 | 217.4 | 37.3 | 2525 |
| PETROLEUM REFINING[3] | | | | | | | | | | | |
| EMPLOYMENT(1,000) | 150-249 | OVER 2500 | 1.9 | 16.2 | 2.2 | 4.7 | 43.3 | 3.4 | 15.0 | | 100.8 |
| WAGES IN MILLIONS OF $ | (D) | (D) | 23.1 | 206.9 | 25.6 | 55.3 | 537.6 | 40.5 | 190.8 | | 1247.1 |
| PETROLEUM [5] PRODUCTION | | | | | | | | | | | |
| IN 1974 MILLION BARRELS | | 4.4 | 39.0 | 59.6 | 72.7 | 88.5 | 2193.8 | 351 | 323 | 70.6 | 3202.6 |
| QUADRILLION BTU's[6] | | (.025) | (.22) | (.35) | (.42) | (.51) | (12.72) | (2.04) | (1.87) | (.41) | (18.6) |
| REFINED OIL USE [7] 1974 | | | | | | | | | | | |
| HEATING(MILLION BARRELS)[8] | 134.9 | 252.0 | 73.2 | 129.0 | 16.3 | 39.5 | 19.8 | 14.9 | 27.4 | 3.1 | 710 |
| (QUADS) | (.78) | (1.46) | (.42) | (.75) | (.09) | (.23) | (.11) | (.09) | (.16) | (.02) | (4.12) |
| ELECTRICITY (MILLION BARRELS)[9] | 73.6 | 154.6 | 156.8 | 35.4 | 11.6 | 6.4 | 27.2 | 12.5 | 81.3 | .4 | 599.9 |
| (QUADS) | (.43) | (.90) | (.91) | (.21) | (.07) | (.04) | (.16) | (.07) | (.47) | (.002) | (3.25) |

## TABLE J-9 (CONT.)

## REGIONAL ENERGY FACTS FOR THE UNITED STATES

| | REGION 1 | REGION 2 | REGION 3 | REGION 4 | REGION 5 | REGION 6 | REGION 7 | REGION 8 | REGION 9 | REGION 10 | TOTAL U.S. |
|---|---|---|---|---|---|---|---|---|---|---|---|
| GASOLINE(1973) MILLION BARRELS[10] | 126.9 | 342.3 | 402.2 | 457.0 | 165.0 | 213.7 | 274.9 | 127.0 | 321.7 | 2.5 | 2433.5 |
| (QUADS) | (.74) | (1.99) | (2.33) | (2.65) | (.96) | (1.24) | (1.60) | (.74) | (1.87) | (.01) | (14.1) |
| INDUSTRIAL FUEL[11] | 25.7 | 52.0 | 51.8 | 44.5 | 10.3 | 11.1 | 26.5 | 16.6 | 31.2 | 1.2 | 271.0 |
| (QUADS) | (.15) | (.31) | (.30) | (.26) | (.06) | (.06) | (.15) | (.10) | (.18) | (.01) | (1.58) |
| OTHER TRANSPORTATION (MILLION BARRELS)[12] | 15.0 | 66.3 | 76.4 | 68.7 | 43.0 | 42.1 | 10[illegible].3 | 36.3 | 69.7 | 2.5 | 525.3 |
| (QUADS) | (.09) | (.38) | (.44) | (.40) | (.25) | (.24) | (.60) | (.21) | (.40) | (.01) | (3.05) |
| JET FUEL[13] (MILLION BARRELS) | | | | | | | | | | | 305 |
| (QUADS) | | | | | | | | | | | (1.77) |
| OTHER FUEL USES (MILLION BARRELS)[14] | | | | | | | | | | | 33.1 |
| (QUADS) | | | | | | | | | | | (.19) |
| OTHER PRODUCTS (MILLION BARRELS)[15] | | | | | | | | | | | 864.4 |
| (QUADS) | | | | | | | | | | | (5.01) |
| GAS SALES BY UTILITIES 1973[16] (QUADS) | .262 | 1.670 | 1.309 | 3.958 | .922 | 1.78 | 3.26 | 1.03 | 2.26 | .027 | 16.48 |
| ELECTRICITY 1974[17] GENERATED($10^9$kw-h) | 76.7 | 254.1 | 347.6 | 363.2 | 184.4 | 120.6 | 255.7 | 101.4 | 252.8 | 2.0 | 1958 |
| (QUADS)[18] | (.26) | (.87) | (1.18) | (1.24) | .63 | (.41) | (.87) | (.35) | (.86) | (.01) | (6.68) |
| HYDRO($10^9$kwh) | 5.216 | 30.100 | 19.312 | 3.598 | 27.053 | 12.3 | 9.7 | 28.2 | 135.8 | 0.3 | 271 |
| (QUADS) | (.018) | (.103) | (.066) | (.012) | (.092) | (.04) | (.03) | (.09) | (.46) | (.001) | (.92) |
| FOSSIL FUELED($10^9$kw-h) | 69.1 | 235.5 | 284.9 | 340.4 | 164.4 | 108.3 | 199.6 | 78.7 | 231.0 | 1.5 | 1713 |
| (QUADS) | (.24) | (.80) | (.97) | (1.16) | (.56) | (.37) | (.68) | (.27) | (.79) | (.005) | (5.84) |
| REFINING CAPACITY[19] 1976(1000 b/cd) OF CRUDE | | 1497.4 | 264.6 | 2519.6 | 587.3 | 838.6 | 6326.0 | 665.9 | 2386.6 | 74.1 | 15,074.8 |

## FOOTNOTES TO TABLE J-9

[1] U.S. Bureau of the Census, Statistical Abstracts of the United States, 1975, 96th Edition, 1975.

[2] U.S. Bureau of the Census, 1972 Census of Mineral Industries, General Summary, pp. 1-11 to 1-14.

[3] U.S. Bureau of the Census, 1972 Census of Manufacturers, General Summary, pp. 1-179 to 1-180.

[4] "D" indicates data withheld by the Census Bureau.

[5] Department of the Interior, Bureau of Mines, Quantity and Value of Crude Petroleum, Produced and Approximate Number of Producing Wells in the U.S.: 1974.

[6] The approximate figure $5.8 \times 10^6$ Btu/barrel was used for all oils.

[7] Jet Fuel and Other Products are not available by Demand Region.

[8] Department of the Interior, Bureau of Mines, Sales of Fuel Oil and Kerosine in 1974, Tables 5, 6, 7, Heating Oils.

[9] Bureau of Mines, Sales of Fuel Oil and Kerosine in 1974, Table 13, Electric Utility Company Use.

[10] World Almanac, 1975, Motor Fuel Consumption (Highway), data are for 1973.

[11] Bureau of Mines, Sales of Fuel Oil and Kerosine in 1974, Tables 8 and 9, Industrial and Oil Company Use.

[12] Bureau of Mines, Sales of Fuel Oil and Kerosine in 1974, Tables 10, 11, 12, 14, Includes Railroads, Vessels, Military, On-highway diesel, Off-highway diesel.

[13] Department of the Interior, Bureau of Mines, Petroleum Statement, 1974, Table 16, United States Jet Fuel Production in 1974.

[14] Bureau of Mines, Sales of Fuel Oil and Kerosine in 1974, Tables 1, 2, 3, All Other Uses for Kerosine, Distillates, and Residual.

[15] Bureau of Mines, Petroleum Statement, 1974, Table 16, United States Production of Ethane, KRG, Petrochemical Feed-Stocks, Special Naphthas, Lube Oil, Wax, Coke, Asphalt, Road Oil, Still Gas for Fuel, misc.

## FOOTNOTES TO TABLE J-9 (CONT.)

[16] Bureau of Census, Statistical Abstracts of the United States, 1975, Table 901, p. 542.

[17] Bureau of Census, Statistical Abstracts of the United States, 1975, Table 888, p. 535 and Table 897, p. 540.

[18] 1 billion kWh = .00341 quads.

[19] "Survey of Operating Refineries in the United States," (State capacities as of January 1, 1976), Oil and Gas Journal (March 29, 1976).

percent of all petroleum products were used directly for heating in 1974, 10 percent for electric power generation, and 50 percent for land and water transportation.

The U.S. Geological Survey has recently prepared estimates of crude oil, natural gas, and natural gas liquid.[9] Figure J-27, taken from the above referenced publication, indicates the location of oil and gas fields. The magnitudes of domestic reserves, as estimated in the referenced publication, are given below.

DEMONSTRATED PETROLEUM RESERVES FOR THE UNITED STATES
DECEMBER 31, 1974 (billion barrels)

| REGIONS | | | DEMONSTRATED RESERVES | |
|---|---|---|---|---|
| | | | MEASURED[a] | INDICATED[b] |
| ONSHORE: | 1. | Alaska | 9.944 | 0.013 |
| | 2. | Pacific Coastal States | 2.699 | 1.091 |
| | 3. | Western Rocky Mountains | 0.417 | 0.089 |
| | 4. | Northern Rocky Mountains | 1.461 | 0.256 |
| | 5. | West Texas and Eastern New Mexico | 7.060 | 1.991 |
| | 6. | Western Gulf Basin | 7.082 | 0.587 |
| | 7. | Mid-Continent | 1.805 | 0.211 |
| | 8. | Michigan Basin | 0.082 | 0.008 |
| | 9. | Eastern Interior | 0.283 | 0.009 |
| | 10. | Appalachians | 0.155 | 0.067 |
| | 11. | Eastern Gulf and Atlantic Coastal Plain | 0.042 | 0.006 |
| | | Total Lower 48 Onshore | 21.086 | 4.315 |
| | | Total Onshore United States | 31.030 | 4.328 |
| OFFSHORE (0-200m): | 1A. | Alaska | 0.150 | Negl. |
| | 2A. | Pacific Coastal States | 0.858 | 0.258 |
| | 6A. | Gulf of Mexico | 2.212 | 0.050 |
| | 11A. | Atlantic Coastal States | 0.000 | 0.000 |
| | | Total Lower 48 Offshore | 3.070 | 0.308 |
| | | Total Offshore United States | 3.220 | 0.308 |
| | | Total Lower 48 | 24.156 | 4.623 |
| | | Total Alaska | 10.094 | 0.013 |
| | | TOTAL UNITED STATES | 34.250 | 4.636 |

[a] Identified resources that can be economically extracted with existing technology.

[b] Identified resources economically recoverable if known fluid injection technology is applied.

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[9] Betty M. Miller et al., Geological Estimates of Undiscovered Recoverable Oil and Gas Resources in the United States, U.S.G.S. Bulletin 725, 1975.

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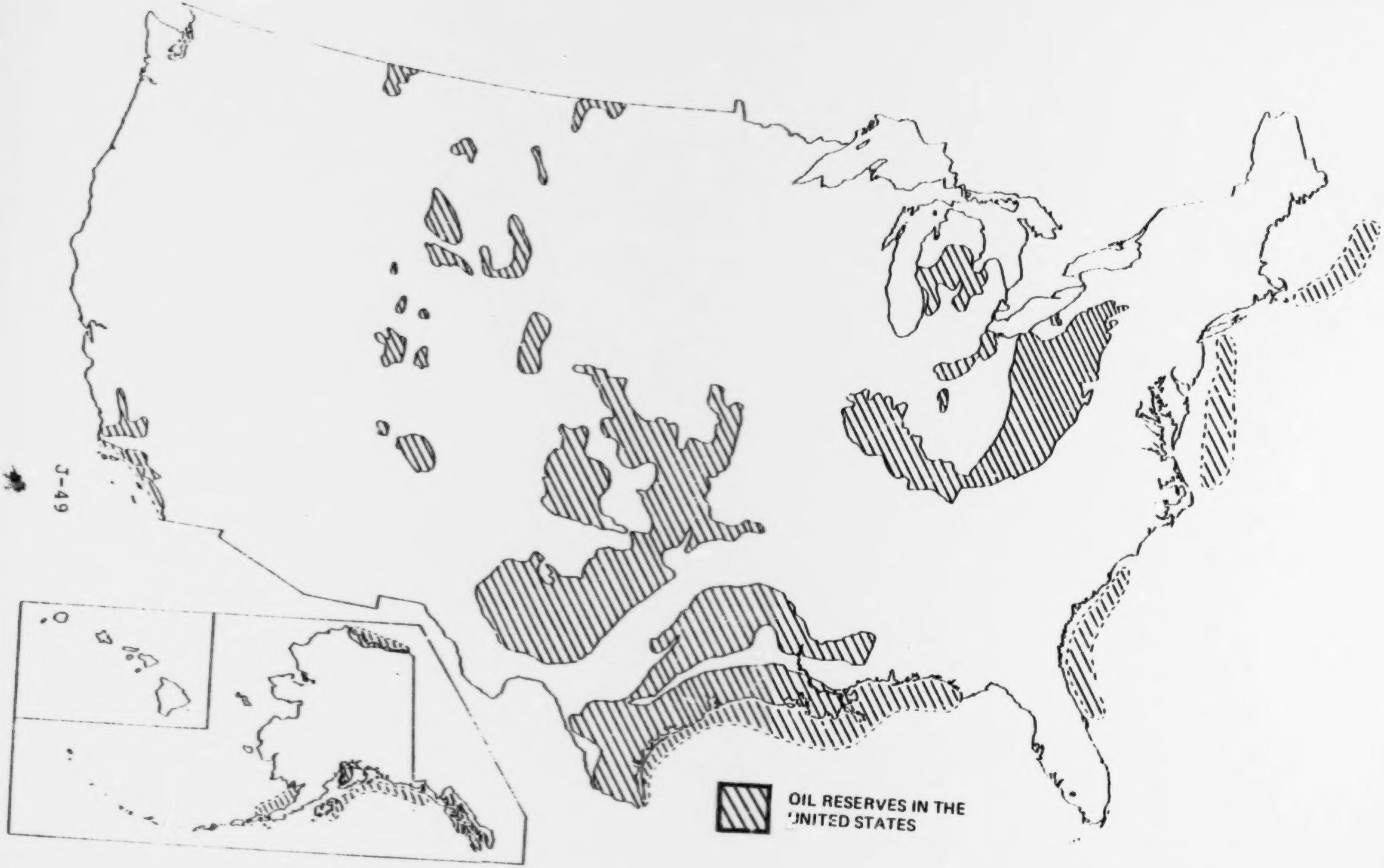
▨ OIL RESERVES IN THE UNITED STATES

Figure J-27. Oil reserves in the United States.

The New England Region produces no significant amounts of fossil fuel, nor has this region significant onshore reserves of coal, oil or gas. New England used 126.9 million barrels of gasoline for highway transportation in 1973, and 250.9 million barrels of kerosine, distillate fuels, and residual fuels in 1974. 134.9 million barrels were used directly for heating, and 73.6 million for electric power generation. Sales of natural gas in 1973 in New England amounted to 0.262 quadrillion Btu's.

The Mid-Atlantic Region produced 4,347 thousand barrels of crude petroleum in 1974. It used 342.3 million barrels of gasoline for highway transportation in 1973, and 528.8 million barrels of kerosine, distillate fuels, and residual fuels in 1974. 252.0 million barrels were used directly for heating and 154.6 million for electric power generation. In 1973, the utilities sold 1.67 quadrillion Btu's in the Mid-Atlantic Region.

The South Atlantic Region produced 39,019 thousand barrels of crude petroleum in 1974. It used 402.2 million barrels of gasoline for highway transportation in 1973, and 362.3 million barrels of kerosine, distillate fuels, and residual fuels in 1974. 73.2 million barrels were used directly for heating, and 156.8 million for electric power generation. In 1973, the utilities sold 1.31 quadrillion Btu's of gas in this region.

The East North Central Region produced 59,581 thousand barrels of crude petroleum in 1974. It used 457.0 million barrels of gasoline for highway transportation in 1973, and 282.7 million barrels of kerosine, distillate fuels, and residual fuels in 1974. 129.0 million barrels were used directly for heating, and 35.4 million for electric power generation. In 1973, this region bought 3.96 quadrillion Btu's of gas from the utility companies.

The East South Central Region produced 72,708 thousand barrels of crude oil in 1974. It used 165.0 million barrels of gasoline for highway transportation in 1973, and 83.5 million barrels of kerosine, distillate fuels, and residual fuels in 1974. 16.3 million barrels were used directly for heating and 11.6 million for electric power generation. In 1973, it purchased 0.922 quadrillion Btu's of gas from the utility companies.

The West North Central Region produced 88,549 thousand barrels of crude petroleum in 1974. It used 213.7 million barrels of gasoline for highway transportation in 1973, and 100.9 million barrels of kerosine, distillate fuels, and residual fuels in 1974. 39.5 million barrels were used directly for heating, and 6.4 million for electric power generation. In 1973, the region purchased 1.783 quadrillion Btu's of gas from the utility companies.

The West South Central Region produced 68 percent of domestic crude petroleum in 1974. Over 200,000 persons were employed in extraction and refining. The region had a population of 20,584,000 and a labor force of 8,509,000 with 4.7 percent unemployment. Energy-related sources of employment were:

| | NUMBER EMPLOYED | WAGES ($ MILLION) |
|---|---|---|
| Coal Mining | 1,000 | 11.9 |
| Petroleum and Gas Extraction | 161,000 | 1,707.6 |
| Petroleum Refining | 43,300 | 537.6 |

SMSA's with over a million inhabitants on April 16, 1975 were:

| | |
|---|---|
| Dallas-Ft. Worth, TX | 2,464,000 |
| Houston, TX | 2,168,000 |
| New Orleans, LA | 1,083,000 |

The region produced 2,193,762 thousand barrels of crude in 1974. It used 274.9 million barrels of gasoline for highway transportation in 1973, and 187.2 million barrels of kerosine, distillate fuels, and residual fuels in 1974. 19.8 million barrels were used directly for heating, and 27.2 million for electric power generation. In 1973, the region used 3.26 quadrillion Btu's of gas.

The Mountain States had a population of 9,411,000 in 1974. The labor force consisted of 4,018,000 with 5.3 percent unemployed. Energy-related sources of employment were:

|  | NUMBER EMPLOYED | WAGES ($ MILLION) |
|---|---|---|
| Coal Mining | 2,500+ | NA |
| Petroleum and Gas Extraction | 22,800 | 235.9 |
| Petroleum Refining | 3,400 | 40.5 |

Large SMSA's in 1975 were:

| | |
|---|---|
| Denver-Boulder, CO | 1,377,000 |
| Phoenix, AZ | 1,127,000 |

The region produced 350,986 thousand barrels of crude in 1974. It used 127.0 million barrels of gasoline for highway transportation in 1973, and 83.9 million barrels of kerosine, distillate fuels, and residual fuels in 1974. 14.9 million barrels were used directly for heating, and 12.5 million for electric power generation. The region purchased 1.03 quadrillion Btu's of gas from the utility companies in 1973.

The Pacific Region includes Hawaii but not Alaska. It had a population of 27,496,000 in 1974, a labor force of 11,940,000, and an unemployment rate of 7.6 percent. Energy-related sources of employment were:

|  | NUMBER EMPLOYED | WAGES ($ MILLION) |
|---|---|---|
| Coal Mining | Under 500 | NA |
| Petroleum and Gas Extraction | 18,300 | 217.4 |
| Petroleum Refining | 15,000 | 190.8 |

Large SMSA's in 1975 were:

| | |
|---|---|
| Anaheim-Santa Ana-Garden Grove, CA | 1,597,000 |
| Los Angeles-Long Beach, CA | 6,924,000 |
| Portland, OR | 1,062,000 |
| Riverside-San Bernadino-Ontario, CA | 1,197,000 |
| San Diego, CA | 1,470,000 |
| San Francisco-Oakland, CA | 3,143,000 |
| San Jose, CA | 1,156,000 |
| Seattle-Everett, WA | 1,383,000 |

The region produced 323,000 thousand barrels of crude in 1974. It used 321.7 million barrels of gasoline for highway transportation in 1973, and 212.4 million barrels of kerosine, distillate fuels, and residual fuels in 1974. 27.4 million barrels were used directly for heating, and 81.3 million for electric power generation. The region purchased 2.26 quadrillion Btu's of gas from the utility companies in 1973.

Alaska produced 70,603 thousand barrels of crude oil in 1974. It used 2.5 million barrels of gasoline for highway transportation in 1973, and 2.5 million barrels of kerosine, distillate fuels, and residual fuels in 1974. 3.1 million barrels were used directly for heating, and 0.4 million for electric power generation. Alaska purchased .027 quadrillion Btu's of natural gas from the utility company in 1973.

## B. Subregional Descriptions

### 1. Gulf of Mexico

### 1.1 Physiography, Oceanography, and Climate

#### Physiography

...The Gulf of Mexico presently represents a subsiding ocean basin partially filled with sediment. The abyssal Gulf is underlain by a simatic (oceanic type) crust; Wilhelm and Ewing (1972) believe that this crust developed to the late Paleozoic. In the Jurassic (about 150 to 180 million years ago) the Gulf was a shallow enclosed sea similar to the present Caspian Sea in southwest Asia and extensive evaporites of salt and anhydrite were deposited. Isolation of the Gulf waters may have been caused by extensive growth of carbonates across the west Florida shelf to the Yucatan Peninsula. Subsidence of the Gulf was as great as 10,000 feet during the Cretaceous. The opening of the Gulf occurred during the Laramide mountain building revolution (Cretaceous to Paleocene) when the carbonate growth was retarded. Subsequent erosion between Florida and the Yucatan has constructed an extensive opening to the Gulf bounded by the Campeche slope and escarpment on the southwest and the Florida slope and escarpment to the northeast. Subsidence, sedimentation, and erosion have built the submarine topography.

The continental shelf is a gently sloping submarine plain (less than 1°) of varying width forming part of the border of the continent out to a water depth of approximately 450 feet, at which point the continental slope begins. The continental slope has a steeper gradient (approaching 5°), extending from the continental shelf to the oceanic depths. The northeastern Gulf shelf varies in width from about 12 miles off the Mississippi River delta to about 140 miles off Crystal River, Florida...

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Note: All information in Section J.B.1 was taken from the Department of the Interior, Bureau of Land Management, 1975 Environmental Impact Statement for the Gulf of Mexico OCS Lease Sale #41. The indented material has been quoted directly from Volume I of this document.

## Geologic Hazards

A number of important geologic hazards occur in the offshore Gulf of Mexico. In the Texas offshore area the possibility of blowouts exists due to the presence of shallow (about 1000 ft. depth) gas deposits within the sediments. Deeper high pressure zones can also cause blowouts during the drilling operation. A third hazard is soft plastic sea floor laced with surficial faults which can present unstable foundations for rigs. A fourth hazard can occur in rough sea floor conditions where coral heads, sharp reefs and structural troughs occur. Damage to the rig in areas of poorly described roughness can occur by jamming the legs or having legs slip off rough surfaces. The problem of locating rigs on a soft plastic sea floor is compounded in offshore Louisiana along the steeper slopes of the Mississippi River delta primarily off Main South and Southwest Passes...

Other hazards include subsidence and/or rise in sea level along the coastal lands of Texas and Louisiana, mud slides in the Mississippi Delta, submerged Karst topography (irregular topography) which presents lost-circulation zones during drilling operations, high geopressure in Mississippi, earthquakes, active faults, hydrocarbon seeps and unstable seep mounds, in the offshore Gulf. Bathymetric prominences formed by coral growth, reef scarps and troughs also pose a hazard to installation of offshore facilities.

## Physical Oceanography

Circulation in the Gulf of Mexico is irregular and is dominated by the 'Loop Current' which is strongest between late summer and winter. The Loop Current, composed of warm Caribbean waters, extends as far north as the Mississippi delta and eddy currents off the major current account for northern growths of coral reefs off Florida and Texas. Water movements in the Gulf of Mexico are controlled by freshwater inflow from land, currents set up by winds, currents and water transport induced by surface gravity waves, tidal currents, currents associated with internal waves, and movement of water masses due to density differences. Figure J-28 presents the general surface circulation of the Gulf of Mexico.

The tides in the Gulf are weakly developed and have a range generally less than 0.7 meters. Tidal regimes for the

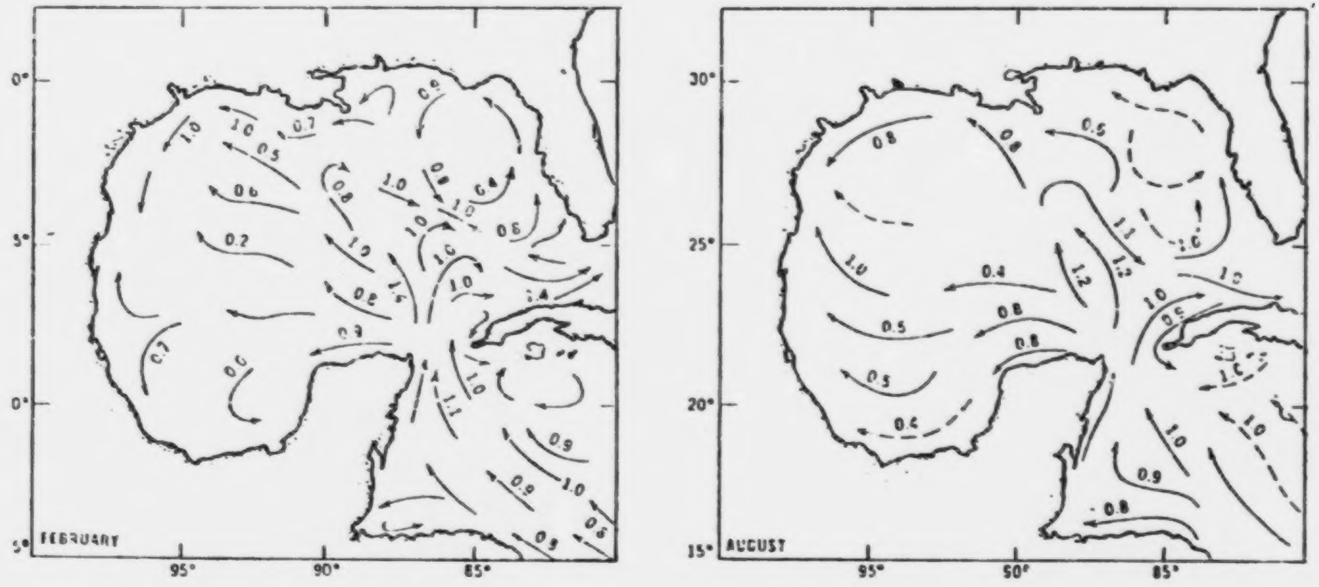
FEBRUARY
95°
90°
85°
AUGUST
30°
25°
20°
15°
95°
90°
85°

Figure J-28. Generalized surface circulation in the Gulf of Mexico inferred from logs of ships at sea. The numbers refer to current speeds in knots, as estimated from ships' drift. (U.S. Department of the Interior, Final Environmental Statement, Gulf of Mexico, OSC Sale No. 41, Vol. 1, p. 70.)

Gulf are displayed in Figure J-29. Though the tidal range is small, tides do have an important role in modifying currents and water movement through narrow passages.

## Climate

The climate of the Gulf of Mexico region is broadly determined by the huge continental land mass lying to the north and west, the subtropical latitude, the influence of the persistent Atlantic high-pressure system (Bermuda-Azores) and the warm waters of the Gulf itself...

The Azores-Bermuda atmospheric high pressure cell dominates the circulation over the Gulf, particularly during the spring and summer months. In late summer there is general northward shift of the circulation and the Gulf comes under the more direct influence of the equatorial low pressure belt. During the relatively constant summer conditions, the southerly position of the Azores-Bermuda cell brings about predominance of southeasterly winds. The winds tend to become more southerly in the northern part of the Gulf. During the winter, winds usually blow from easterly directions with fewer southerlies but more northerlies. Winds from west and southwest are rare anytime during the year.

Near the Gulf coast winds are more variable than over the open waters of the Gulf because the coastal winds fall more directly under the influence of the moving cyclonic storms that are characteristic of the continent...

The largest and most destructive storms affecting the Gulf of Mexico and adjacent coastal zone are tropical cyclones. These have their origin over the warm tropical waters of the central Atlantic Ocean, Caribbean Sea or southeastern Gulf of Mexico. They occur most frequently between June and late October (Brower, et al., 1972) and there is a relatively high probability that tropical cyclones will cause damage in the Gulf of Mexico each year. Statistics for hurricanes and tropical cyclones are often lumped together since it is often difficult, especially in the older records, to determine the storm intensity while at sea. The probability of a tropical cyclone or hurricane influencing the north-central Gulf coast during any given year is one in six...

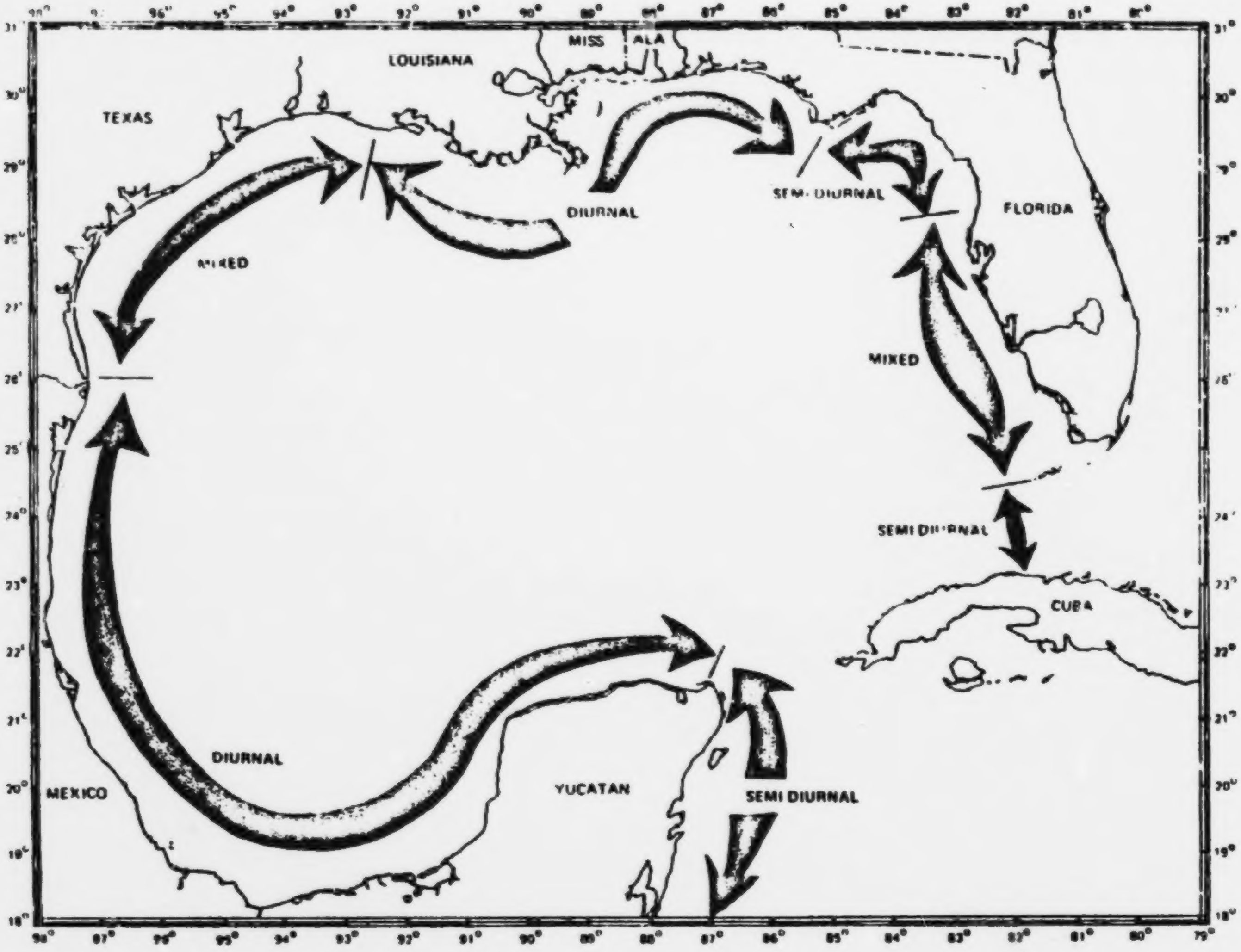
TEXAS
LOUISIANA
MISS
ALA
FLORIDA
MIXED
DIURNAL
SEMI-DIURNAL
MIXED
SEMI DIURNAL
CUBA
DIURNAL
MEXICO
YUCATAN
SEMI DIURNAL
98°
97°
96°
95°
94°
93°
92°
91°
90°
89°
88°
87°
86°
85°
84°
83°
82°
81°
80°
79°
31°
30°
29°
28°
27°
26°
25°
24°
23°
22°
21°
20°
19°
18°

Figure J-29. Gulf of Mexico tidal regimes. (C.K. Eleuterius, Mississippi Superport Study, Environmental Assessment, 1974.)

## 1.2 Resources -- Description and Principal Uses

The principal resource value of the Gulf resides in its tremendous biological productivity. What follows is a description of that resource.

### Commercial Resources

The Gulf of Mexico is by far the most productive fishery region in the United States, with much of the activity concentrated near the Mississippi Delta. Gulf landings account for over 30 percent of the entire U.S. catch. The productivity of the Gulf is considered second only to that of the Peruvian coast.

The Gulf fishery is dominated by shrimp, crab and oyster shellfisheries which are generally worth three or four times as much as the finfish. Pink, white and brown shrimp and blue crabs are the major commercial species. The finfish industry is dominated by menhaden, which are processed to produce oil, fish meal and solubles.

Table J-10 presents 1973-1974 landings for the Gulf States where 97.5 percent of the commercial fisheries catch is made up of estuarine-dependent species. These species are particularly vulnerable to pollution introduced by river discharge and tidal action.

TABLE J-10

LANDINGS BY STATES FOR GULF OF MEXICO
1973-1974[1]

| | 1973 | | | | 1974 | | | |
|---|---|---|---|---|---|---|---|---|
| | THOUSAND POUNDS | PERCENT | THOUSAND DOLLARS | PERCENT | THOUSAND POUNDS | PERCENT | THOUSAND DOLLARS | PERCENT |
| Gulf | 1,547,471 | | 268,146 | | 1,772,431 | | 240,836 | |
| Alabama | 39,749 | 2.6 | 18,080 | 6.8 | 36,962 | 2.1 | 17,087 | 7.1 |
| Florida (Gulf) | 99,200 | 6.4 | 43,462 | 16.2 | 104,662 | 5.9 | 48,245 | 20.0 |
| Louisiana | 1,035,959 | 66.9 | 98,446 | 36.7 | 1,228,906 | 69.3 | 86,694 | 36.0 |
| Mississippi | 271,594 | 17.6 | 16,887 | 6.3 | 304,794 | 17.2 | 16,355 | 6.8 |
| Texas | 100,969 | 6.5 | 91,271 | 34.0 | 97,203 | 5.5 | 72,455 | 30.1 |

[1] Landings in interior waters are estimated.

## Biological Resources

The length and biological diversity of the coast of the eastern Gulf of Mexico (Florida) exceed those of any of the other Gulf states. Tidal swamps and marshes fringe the entire coast and submerged vegetation blankets most of the shallow-water bottom. This diversity supplies habitat for numerous species of wildlife (many of them endemic) as well as some sub-tropical birds.

The paramount feature of the central Gulf coast is the Mississippi River delta and its associated seven million or more acres of marsh and estuaries. The Mississippi watershed covers about one-third of the United States, and the resultant freshwater discharge is responsible for the major saltwater dilutions within the central Gulf coast region. The estuaries of Louisiana, the most extensive in the Gulf, supports the third largest shrimp production and the second largest oyster production in the United States (U.S. Dept. of Commerce, 1975).

East of the Mississippi Delta, the proportion of estuaries to the coastal zone diminishes and becomes more commonly characterized by high energy sand beaches. The wetlands which are present are extremely valuable in terms of biological productivity.

Along the northwest Gulf Coast, the marshlands diminish rapidly into a narrow band along the coast, and are nearly absent in the semiarid regions of south Texas. A significant portion of the coastal zone, however, is composed of a vast system of bays and lagoons which are engendered for the most part by the extensive system of barrier islands.

Many of the areas found in the coastal and offshore regions are of particular importance for their aesthetic value, as habitats for rare and endangered species, or as assemblages particularly sensitive to pollutants and physical modifications. Table J-11 presents the rare and endangered species of the Gulf Region.

Most of these key habitats are estuarine; however, the reef communities offshore of Texas and Florida are of interest as the northernmost thriving tropical shallow water coral reefs in the Gulf of Mexico. The East and West Flower Garden banks are located southeast of Galveston, Texas, on the outer edge of the continental shelf. The reef building

TABLE J-11

## SPECIES WITH RARE, ENDANGERED, OR PERIPHERAL STATUS IN THE GULF OF MEXICO

| SPECIES | STATUS | DISTRIBUTION |
|---|---|---|
| BROWN PELICAN | ENDANGERED | BREEDS ON ISLANDS ALONG GULF FROM FLORIDA TO TEXAS |
| FLORIDA GREAT WHITE HERON | RARE | BREEDS IN FLORIDA KEYS, FLORIDA BAY AND S. PENINSULA OF FLORIDA NORTH TO CAPE ROMANO |
| FLORIDA EVERGLADE KITE | ENDANGERED | FRESH WATER MARSHES OF SOUTHERN FLORIDA |
| SOUTHERN BALD EAGLE | ENDANGERED | NESTS IN ESTUARINE AREAS FROM FLORIDA TO TEXAS |
| ARCTIC PEREGRENE FALCON | ENDANGERED | IN MIGRATION ALONG THE BEACHES OF OUTER GULF COAST ISLANDS |
| ATTWATER'S GREATER PRAIRIE CHICKEN | ENDANGERED | DISJUNCT POPULATIONS IN TEXAS |
| CAPE SABLE SPARROW | ENDANGERED | FRESH AND BRACKISH WATER MARSHES IN SOUTHWESTERN FLORIDA |
| AMERICAN ALLIGATOR | ENDANGERED | MISSISSIPPI WEST TO CORPUS CHRISTI, TEXAS |
| AMERICAN CROCODILE | PERIPHERAL | S. FLORIDA AND FLORIDA KEYS |
| GREEN TURTLE | PERIPHERAL | GULF COAST WATER - PRESENT DURING SUMMER. MAY NEST ON FLORIDA COAST |
| RED WOLF | ENDANGERED | SOUTHEASTERN TEXAS AND SOUTHWESTERN LOUISIANA |
| FLORIDA MANATEE | ENDANGERED | COASTAL AREAS OF FLORIDA |

TABLE J-11 (CONT.)

| SPECIES | STATUS | DISTRIBUTION |
|---|---|---|
| WHOOPING CRANE | ENDANGERED | WINTERS AT ARANSES NATIONAL WILDLIFE REFUGE, TEXAS AND NEARBY GULF COAST ISLANDS |
| FLORIDA SANDHILL CRANE | RARE | WEST PRAIRIES OF PENINSULAR FLORIDA AND SOUTHERN MISSISSIPPI |
| ESKIMO CURLEW | ENDANGERED | SPRING MIGRANTS ON TEXAS COAST |
| AMERICAN IVORY BILLED WOODPECKER | ENDANGERED | SOUTHEAST TEXAS |
| RED COCKADED WOODPECKER | ENDANGERED | OPEN, OLD PINE WOODLANDS IN GULF COAST REGION - FLORIDA TO EASTERN TEXAS |
| FLORIDA PANTHER | ENDANGERED | FOUR COUNTIES IN FLORIDA |
| KEY DEER | ENDANGERED | KEY DEER NATIONAL WILDLIFE REFUGE, FLORIDA |
| HOUSTON TOAD | ENDANGERED | LOBLOLLY PINE, HOUSTON TEXAS |

Source: William F. Gusey, Petroleum Production and Fish and Wildlife Resources, The Gulf of Mexico, Cook Inlet, Alasks, Santa Barbara Channel, California, Appendix 6.

corals Porites asteoides, Montastria annularis, Montastrea cavernosa and Dioloria spp. are the same as those found in Bermuda, though no alcyonarian corals are present in the West Flower Garden.

The bays, estuaries and associated salt marshes, as mentioned earlier, function as hatcheries and nurseries for numerous species of marine and estuarine fish and invertebrates. The salt marshes which line much of the Gulf Coast excluding Texas, and that are quite extensive in Southeastern Louisiana, are extremely productive. They supply a significant quantity of primary production in the form of detritus to offshore Gulf waters. Several low salinity communities are common in the upper estuaries. Oyster reefs, dominated by Crassostrea virginica, Spartina-Juncus marshes, and mangrove swamps, are such communities.

Mangrove swamps are restricted to the southern half of the Florida Gulf coast and some of the barrier islands in Louisiana by temperature constraints. These swamps, dominated by three species of mangrove, support a low diversity of plant species but support many animal species, particularly birds. Egrets, herons, ibis, ducks, kingfishers, crab hawks, stilts and pelicans feed on estuarine fish and invertebrates found in the swamps. Florida mangrove swamps also serve as nursery grounds for menhaden, black mullet, spotted sea trout, snook tarpon, red drum, mangrove snapper, pompano and pink shrimp.

The barrier islands along Texas, Louisiana and Florida are composed primarily of high energy beaches. They provide essential habitat for shore and wading bird rookeries and for the loggerhead turtle.

### Population and Employment

The Gulf of Mexico region is a major supplier of crude oil, petroleum products and natural gas to other regions of the United States. Much of the economy and growth of the coastal area is governed by these oil and gas activities. Table J-12 presents population and employment data for 1970. In all areas employment and personal income are smaller percentages of the national figures than population. A significant trend in these five states has been the decline of farm employment and an increase in employment in manufacturing, mining, construction, transportation and services.

## TABLE J-12

## POPULATION AND EMPLOYMENT BY INCOME REGIONS ON GULF COAST COMPARED TO TOTAL U.S., 1970

| | TOTAL U.S. | WESTERN (Coastal Texas) | CENTRAL (Coastal Louisiana) | EASTERN (Coastal Miss. Ala., Fla.) |
|---|---|---|---|---|
| Total Population | 203,857,864 | 4,883,064 | 2,900,230 | 3,267,717 |
| % of U.S. | -- | 2.4 | 1.4 | 1.6 |
| Total Employment | 79,306,527 | 1,816,283 | 963,028 | 1,138,419 |
| % of U.S. | -- | 2.3 | 1.2 | 1.4 |
| Total Personal Income[1] | 708,583,931 | 15,059,700 | 7,793,192 | 9,150,233 |
| % of U.S. | -- | 2.1 | 1.1 | 1.3 |

[1] Total personal income in thousands of 1967 dollars.

## 1.3 Environmental Quality

### Air Quality

Prevailing meteorological conditions along the Gulf Coast are such that emissions from offshore facilities will remain over the sea, whereas emissions from nearshore operations may further degrade air quality over the coastal lands. Table J-13 presents ambient air quality standards applied for each of the Gulf Coast States. Table J-14 summarizes the Gulf Coast Air Quality Control Regions and their ability to meet national standards for sulfur dioxide, suspended particulates, carbon monoxide and oxidants.

A severe air quality problem exists along the Texas coast, particularly in the Corpus Christi and Houston AQCR's. Photochemical oxidants are a major problem in the Upper Gulf Coast Area of Texas where most of the photochemical industries and metropolitan areas are concentrated.

### Water Quality

Current water quality problems exist in major metropolitan areas such as Houston, New Orleans and Mobile, or areas of concentrated petrochemical industries. Other sources of water pollution along the coast are fish and oil processing plants, pulp and paper mills, foundries and smelters.

## TABLE J-13

## STATE AMBIENT AIR QUALITY STANDARDS (PRIMARY/SECONDARY)

## (GULF COAST STATES)

| | FLORIDA | ALABAMA | MISSISSIPPI | LOUISIANA | TEXAS | NAAQS |
|---|---|---|---|---|---|---|
| SUSPENDED PARTICULATE MATTER (mg/m$^3$): | | | | | | |
| Annual geometric mean | 60/60 (50)[1] | 75/60 | 75/60 | 75/60 | 75/60 | 75/60 |
| Maximum 24-hour mean | 150/150 (100) | 260/150 | 260/150 | 260/150 | 260/150 | 260/150 |
| COEFFICIENT OF HAZE: | | | | | | |
| Annual geometric mean | - | - | - | .6 COH/1000 linear ft | - | - |
| Annual arithmetic mean | - | - | - | .75 COH/1000 linear ft | - | - |
| Maximum 24-hour mean | - | - | - | 1.5 COH/1000 linear ft | - | - |
| SULFUR DIOXIDE (mg/m$^3$): | | | | | | |
| Annual mean | 60/60 (8.6) | 80/- | 80/- | 80/60 | 80/- | 80/- |
| Maximum 24-hour mean | 260/260 (28.6) | 365/- | 365/- | 365/260 | 365/- | 365/- |
| Maximum 4-hour mean | - (57.2) | - | - | - | - | - |
| Maximum 3-hour mean | 1300/1300 | -/1300 | -/1300 | -/1300 | -/1300 | -/1300 |
| Maximum 1-hour mean | - (286) | - | - | - | - | - |
| CARBON MONOXIDE (mg/m$^3$): | | | | | | |
| Maximum 8-hour mean | 10/10 (1.9) | 10/10 | 10/10 | 10/10 | 10/10 | 10/10 |
| Maximum 1-hour mean | 40/40 (14) | 40/40 | 40/40 | 40/40 | 40/40 | 40/40 |
| HYDROCARBONS (mg/m$^3$): (Other than methane.) | | | | | | |
| Maximum 3-hour mean | 160/160 | 160/160 | 160/160 | 160/160 | 160/160 | 160/160 |
| TOTAL OXIDANTS (mg/m$^3$): | | | | | | |
| Annual mean | - | - | - | - | - | - |
| Maximum 4-hour mean | - | - | - | 50.0/50.0 | - | - |
| Maximum 1-hour mean | 160/160 | 160/160 | 160/160 | 160/160 | 160/160 | 160/160 |
| NITROGEN DIOXIDE (mg/m$^3$): | 100/100 | 100/100 | 100/100 | 100/100 | 100/100 | 100/100 |
| Annual mean | 100/100 | 100/100 | 100/100 | 100/100 | 100/100 | 100/100 |
| SULFURIC ACID MIST, SULFUR TRIOXIDE, OR ANY COMBINATION (mg/m$^3$): | | | | | | |
| Annual mean | - | - | - | 4 | - | - |
| Maximum 24-hour mean | - | - | - | 12 | - | - |
| Maximum 1-hour mean | - | - | - | 30 | - | - |

[1] Parenthetical values supplant state values in Dade, Broward, and Palm Beach Counties.

TABLE J-14

## NUMBER OF STATIONS REPORTING AND NUMBER OF STATIONS AT WHICH STANDARDS WERE EXCEEDED, BY AQCR, 1970-1974

(GULF COAST STATES)

| AIR QUALITY CONTROL REGION | YR | SUSPENDED PARTICULATES |  |  |  |  |  | SULFUR DIOXIDE |  |  |  |  | CARBON MONOXIDE |  |  | OXIDANTS |  | NITROGEN DIOXIDE |  |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
|  |  | ANNUAL |  |  | 24-HOUR |  |  | ANNUAL |  | 24-HR |  | 3-HR |  | 1-HR | 8-HR |  | 1-HR |  |  |
|  |  | # STA | #> SEC | #> PRI | # STA | #> SEC | #> PRI | # STA | #> STD | # STA | #> STD | #> STD | # STA | #> STD | #> STD | # STA | #> STD | # STA | #> STAN STD |
|  | UG/CU.M | (1) | 60 | 75 | (2) | 150 | 260 | (1) | 80 | (2) | 365 | 1300 | (2) | 40* | 10* | (2) | 160 | (1) | 100 |
|  | P.P.M. |  | - | - |  | - | - |  | .03 |  | .14 | .50 |  | 35 | 9 |  | .08 |  |  |
| 005 MOBILE-PENSACOLA-PANAMA CITY- |  | ( 19) |  |  |  |  |  | ( 11 + 5) |  |  |  |  | ( 0) |  |  | ( 5) |  | ( 0) |  |
| S. MISSIALA-FL-MISS) | 70 | 0 | 7 | 0 | 3 | 0 | 0 | 0 | 0 | 4 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
|  | 71 | 0 | 7 | 7 | 4 | 0 | 0 | 0 | 0 | 3 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
|  | 72 | 2 | 7 | 0 | 5 | 0 | 0 | 1 | 0 | 13 | 1 | 1 | 1 | 0 | 0 | 2 | 2 | 0 | 0 |
|  | 73 | 3 | 1 | 1 | 26 | 13 | 3 | 2 | 0 | 27 | 1 | 0 | 1 | 0 | 0 | 3 | 3 | 0 | 0 |
|  | 74 | 23 | 10 | 3 | 40 | 12 | 3 | 12 | 0 | 26 | 0 | 0 | 1 | 0 | 0 | 2 | 2 | 0 | 0 |
| 049 JACKSONVILLE-BRUNSWICK |  | ( 11) |  |  |  |  |  | ( 3 + 11) |  |  |  |  | ( 0) |  |  | ( 3) |  | ( 0) |  |
| (FLA-GA) | 70 | 11 | 5 | 3 | 11 | 5 | 3 | 4 | 0 | 12 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
|  | 71 | 10 | 8 | 4 | 11 | 7 | 3 | 3 | 7 | 13 | 1 | 1 | 2 | 0 | 1 | 1 | 0 | 0 | 0 |
|  | 72 | 2 | 1 | 7 | 14 | 3 | 1 | 1 | 0 | 6 | 0 | 0 | 4 | 1 | 4 | 3 | 0 | 0 | 0 |
|  | 73 | 2 | 2 | 7 | 24 | 11 | 4 | 2 | 7 | 12 | 3 | 0 | 1 | 0 | 0 | 1 | 0 | 0 | 0 |
|  | 74 | 2 | 0 | 0 | 5 | 0 | 0 | 1 | 7 | 3 | 2 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 050 SOUTHEAST FLORIDA |  | ( 3) |  |  |  |  |  | ( 1 + 0) |  |  |  |  | ( 0) |  |  | ( 0) |  | ( 10) |  |
|  | 70 | 1 | 1 | 0 | 1 | 0 | 0 | 1 | 0 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
|  | 71 | 1 | 1 | 0 | 1 | 0 | 0 | 1 | 0 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
|  | 72 | 1 | 1 | 0 | 6 | 0 | 0 | 0 | 0 | 2 | 0 | 0 | 1 | 0 | 0 | 1 | 0 | 0 | 0 |
|  | 73 | 0 | 7 | 7 | 42 | 4 | 1 | 1 | 0 | 7 | 0 | 0 | 1 | 0 | 0 | 4 | 3 | 0 | 0 |
|  | 74 | 0 | 0 | 0 | 1 | 0 | 0 | 0 | 0 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 051 SOUTHWEST FLORIDA |  | ( 1) |  |  |  |  |  | ( 1 + 0) |  |  |  |  | ( 0) |  |  | ( 0) |  | ( 0) |  |
|  | 70 | 0 | 0 | 0 | 0 | 0 | 0 | 3 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
|  | 71 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
|  | 72 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
|  | 73 | 0 | 0 | 0 | 3 | 0 | 0 | 0 | 0 | 1 | 0 | 0 | 0 | 0 | 0 | 1 | 1 | 0 | 0 |
|  | 74 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 052 WEST CENTRAL FLORIDA |  | ( 11) |  |  |  |  |  | ( 8 + 3) |  |  |  |  | ( 0) |  |  | ( 0) |  | ( 10) |  |
|  | 70 | 3 | 1 | 1 | 3 | 0 | 0 | 2 | 0 | 3 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
|  | 71 | 2 | 7 | 0 | 3 | 1 | 0 | 3 | 0 | 3 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
|  | 72 | 3 | 1 | 1 | 3 | 0 | 0 | 3 | 0 | 3 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
|  | 73 | 0 | 7 | 7 | 15 | 5 | 1 | 1 | 0 | 14 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
|  | 74 | 0 | 0 | 0 | 1 | 0 | 0 | 0 | 0 | 2 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

Source: Monitoring and Air Quality Trends Report, 1974, EPA-450/1-76-001, February 1976.

# TABLE J-14 (CONT.)

| AIR QUALITY CONTROL REGION | YR | SUSPENDED PARTICULATES ANNUAL # STA (1) | #> SEC 60 | #> PRI 75 | 24-HOUR # STA (2) | #> SEC 150 | #> PRI 260 | SULFUR DIOXIDE ANNUAL # STA (1) | #> STD 80 .03 | 24-HR # STA (2) | #> STD 365 .14 | 3-HR #> STD 1300 .50 | CARBON MONOXIDE # STA (2) | 1-HR #> STD 40* 35 | 8-HR #> STD 10* 9 | OXIDANTS # STA (2) | 1-HR #> STD 160 .08 | NITROGEN DIOXIDE # STA (1) | #>AM STD 100 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| UG/CU.M: | | | 60 | 75 | | 150 | 260 | | 80 | | 365 | 1300 | | 40* | 10* | | 160 | | 100 |
| P.P.M: | | | - | - | | - | - | | .03 | | .14 | .50 | | 35 | 9 | | .08 | | |
| 106 SOUTHERN LOUISIANA-SOUTHEAST TEXAS (LA-TEX) | | ( 3) | | | | | | ( 11 + 6) | | | | | ( 0) | | | ( 6) | | ( 0) | |
| | 70 | 4 | 4 | 1 | 6 | 0 | 0 | 3 | 0 | 4 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | 71 | 7 | 7 | 1 | 14 | 2 | 1 | 2 | 0 | 4 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | 72 | 8 | 6 | 3 | 10 | 2 | 0 | 11 | 0 | 16 | 0 | 0 | 3 | 0 | [illegible] | 4 | 4 | 0 | 0 |
| | 73 | 11 | 9 | ? | 20 | 9 | 2 | 11 | 0 | 22 | 0 | 0 | 1 | 0 | 1 | 2 | 2 | 0 | 0 |
| | 74 | 6 | 3 | ? | 20 | 1 | 0 | 13 | 0 | 28 | 0 | 0 | 3 | 0 | 1 | 3 | 2 | 2 | 0 |
| 213 BROWNSVILLE-LAREDO (TEX) | | ( 7) | | | | | | ( 1 + 0) | | | | | ( 0) | | | ( 0) | | ( 0) | |
| | 70 | 3 | 3 | 3 | 4 | 3 | 2 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | 71 | 3 | 3 | 2 | 16 | 15 | 10 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | 72 | 7 | 6 | 6 | 14 | 9 | 7 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | 73 | 3 | 3 | 2 | 4 | 3 | 2 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | 74 | 0 | ? | ? | 5 | 3 | 1 | 0 | 0 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 214 CORPUS CHRISTI-VICTORIA (TEX) | | ( 7) | | | | | | ( 5 + 2) | | | | | ( 0) | | | ( 2) | | ( 7) | |
| | 70 | 1 | 1 | 0 | 4 | 0 | 0 | 1 | 0 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | 71 | 10 | 7 | 2 | 19 | 15 | 4 | 1 | ? | 5 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | 72 | 12 | 6 | 5 | 13 | 5 | 1 | 4 | 0 | 5 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | 73 | 7 | 4 | 1 | 18 | 6 | 1 | 3 | 0 | 7 | 0 | 0 | 0 | 0 | 0 | 1 | 1 | 0 | 0 |
| | 74 | 0 | ? | ? | 15 | 3 | 0 | 0 | 0 | 4 | 0 | 0 | 1 | 0 | 0 | 2 | 2 | 0 | 0 |
| 215 METROPOLITAN DALLAS-FORT WORTH (TEX) | | ( 3) | | | | | | ( 1 + 0) | | | | | ( 0) | | | ( 5) | | ( 10) | |
| | 70 | 3 | 3 | 3 | 16 | 7 | 3 | 2 | 0 | 2 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | 71 | 22 | 16 | 8 | 39 | 35 | 19 | 1 | 0 | 4 | 0 | 0 | 0 | 0 | 0 | 1 | 0 | 0 | 0 |
| | 72 | 28 | 16 | 7 | 35 | 13 | 5 | 5 | 0 | 9 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | 73 | 25 | 13 | 5 | 44 | 17 | 1 | 5 | 0 | 11 | 0 | 0 | 0 | 0 | 0 | 2 | 2 | 0 | 0 |
| | 74 | 0 | ? | ? | 40 | 6 | 0 | 1 | 0 | 12 | 0 | 0 | 1 | 0 | 0 | 3 | 2 | 1 | 0 |
| 216 METROPOLITAN HOUSTON-GALVESTON (TEX) | | ( 13) | | | | | | ( 9 + 4) | | | | | ( 0) | | | ( 4) | | ( 10) | |
| | 70 | 8 | 3 | 2 | 12 | 1 | 0 | 1 | 0 | 3 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | 71 | 24 | 14 | 9 | 30 | 13 | 1 | 12 | 0 | 22 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | 72 | 28 | 16 | 8 | 49 | 19 | 0 | 21 | 0 | 36 | 0 | 0 | 0 | 0 | 0 | 1 | 1 | 0 | 0 |
| | 73 | 51 | 32 | 21 | 60 | 30 | 5 | 30 | 0 | 46 | 0 | 0 | 0 | 0 | 0 | 2 | 2 | 0 | 0 |
| | 74 | 1 | ? | ? | 59 | 21 | 3 | 3 | 0 | 54 | 0 | 0 | 3 | 0 | 1 | 5 | 4 | 3 | 0 |

(1) NUMBER OF STATIONS REPORTING A FULL YEAR'S VALID DATA
(2) NUMBER OF STATIONS REPORTING AT LEAST 3 24-HR VALUES OR 400 HOURLY VALUES
? STATIONS WITH INCOMPLETE DATA MAY BE EXCEEDING THE ANNUAL STANDARD; SEE APPENDICES
* CO STANDARDS ARE IN MILLIGRAMS PER CUBIC METER

## 2. Southern California

### 2.1 Physiography, Oceanography, and Climate

### Physiography

The current oil production sites lie on the continental shelf, often called the Southern California Borderland, which extends over 100 miles offshore. The California Borderland, unlike most continental shelves, is highly convoluted, consisting of seven major islands, nine basins and several ridges and banks (see Figure J-30). The depths in the offshore region vary greatly. Submarine ridge crests reach within 4 meters of the surface while the larger basins reach depths over 2,000 meters.

A recent 1974-1975 U.S. Geological Survey in the vicinity of Oxnard, California, revealed the presence of five freshwater aquifers offshore, four of which extend out to the east slope of the Santa Barbara Basin. The other extends below the basin.

There are a number of geologic hazards in Southern California which affect oil production activities and their impacts both onshore and offshore. The greatest of these is earthquake shaking, which may destroy onshore facilities, create leaks in platforms or pipelines, or cause natural hydrocarbon seepage from the ocean floor. The entire California coastal region is in a high seismic risk zone. The Southern California Borderland is located within the circum-Pacific seismic and volcanic belt and has been tectonically active throughout much of Cenozoic time.

Other geologic hazards in the offshore and coastal region include landsliding, flooding, erosion, fault displacement, volcanic hazards, tsunamic hazards and subsidence. Offshore seepage of gas and oil has been found to occur between Point Conception (Santa Barbara County) and Huntington Beach (Orange County), with the largest concentration in the Santa Barbara Channel area. There are probably 50 or 60 natural oil or gas seeps in the offshore area.

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Note: All information in Section J.B.2 was taken from the Department of the Interior, Bureau of Land Management, Proposed 1975 Outer Continental Shelf Oil and Gas General Lease Sale Offshore Southern California, OCS Sale No. 35. The indented material has been quoted directly from this document.

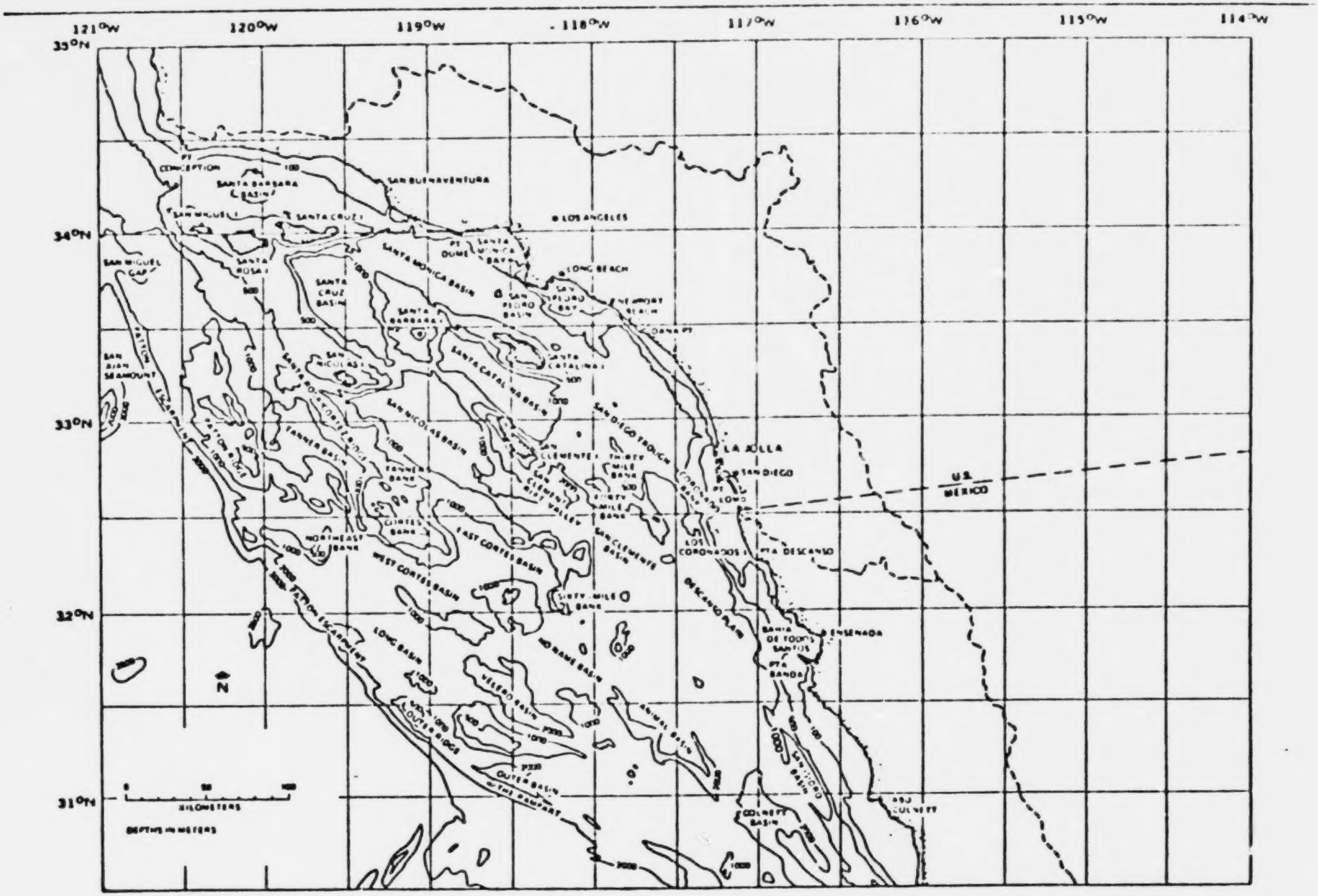
121°W
120°W
119°W
118°W
117°W
116°W
115°W
114°W
35°N
34°N
33°N
32°N
31°N
PT CONCEPTION
SANTA BARBARA BASIN
SAN BUENAVENTURA
SAN MIGUEL I
SANTA CRUZ I
LOS ANGELES
SAN MIGUEL GAP
SANTA ROSA I
PT DUME
SANTA MONICA BAY
SANTA MONICA BASIN
LONG BEACH
SANTA CRUZ BASIN
SAN PEDRO BASIN
SAN PEDRO BAY
NEWPORT BEACH
SANTA BARBARA I
DANA PT
SAN NICOLAS I
SANTA CATALINA I
SANTA CATALINA BASIN
SAN JUAN SEAMOUNT
PATTON ESCARPMENT
SANTA ROSA-CORTES RIDGE
SAN NICOLAS BASIN
SAN DIEGO TROUGH
TANNER BASIN
TANNER BANK
SAN CLEMENTE I
THIRTY MILE BANK
LA JOLLA
SAN DIEGO
PT LOMA
CORONADO BANK
FORTY MILE BANK
SAN CLEMENTE RIFT VALLEY
CORTES BANK
NORTHEAST BANK
EAST CORTES BASIN
SAN CLEMENTE BASIN
LOS CORONADOS I
PTA DESCANSO
WEST CORTES BASIN
SIXTY MILE BANK
DESCANSO PLAIN
U.S.
MEXICO
BAHIA DE TODOS SANTOS
ENSENADA
PTA BANDA
LONG BASIN
NO NAME BASIN
VELERO BASIN
ANIMAL BASIN
SAN ISIDRO BASIN
COLNETT BASIN
OUTER BASIN
PTA COLNETT
N
0
50
100
KILOMETERS
DEPTHS IN METERS
100
500
1000
2000

Figure J-30. The sea floor of the Southern California bight. (U.S. Department of the Interior, Final Environmental Statement, OCS Sale No. 35, Vol. 1, from D.G. Moore, "Submarine Geology of San Pedro Shelf. J. Sed. Petr. 24 (1954), plate 1.)

## Physical Oceanography

Figure J-31 gives a composite picture of the surface circulation in the region of the Southern California Borderline areas. North of Point Conception, the California Current flows southeastward with a mean speed of approximately 15 cm/sec (0.54 km/hr) and a volume transport of 12 x $10^6 m^3$/sec (Pavlova, 1966). There is no true western edge to this current. More than 90 percent of the southeastward transport is within 800 km of the coast of Central California and is located above 300 m depth (Sverdrup and Fleming, 1941).

Within 150 km of the coast, north of Point Conception, the surface currents often flow northwestward along the coast from about November through February. This commonly produces an inshore surface countercurrent (the Davidson Current), which remains until the northwesterly winds resume in the spring.

The Southern California Countercurrent is a nearly permanent feature of the flow pattern in this region and has been found to be well developed in winter and weak in the spring (Schwarlose, 1963). Its location may be influenced by the shape of the coast and the bottom topography, as implied by Sverdrup and Fleming (1941). Estimates of surface speed in the Southern California Countercurrent are comparable to that observed in the California Current itself: 12 to 18 cm/sec (Sverdrup and Fleming, 1941). Transport estimates in this branch of the eddy are only slightly less than that calculated for the California Current (Pavlova, 1966) and appear to vary seasonally with the California Current (Pavlova, 1966; Sverdrup and Fleming, 1941). ...

A persistent north to northwesterly flowing undercurrent is present at depths of more than 150 to 200 m and less than 500 to 800 m in the Southern California Bight. Wooster and Jones (1971) found a subthermocline poleward flow of warm, salty, low oxygen water. The center of the current contains a salinity maximum of 34.4 $^0/00$ to 34.6 $^0/00$, and a sigma-t (i.e., density) level of 26.54. Measurements of salinity and density, which are used to define the distribution of the undercurrent, show that the current is confined by the continental slope in the bight, where it is 20 km wide and 300 m thick. It is broad off Baja, California but narrows to a thin current over the Southern California continental slope, seaward of the 200 m isobath. ...

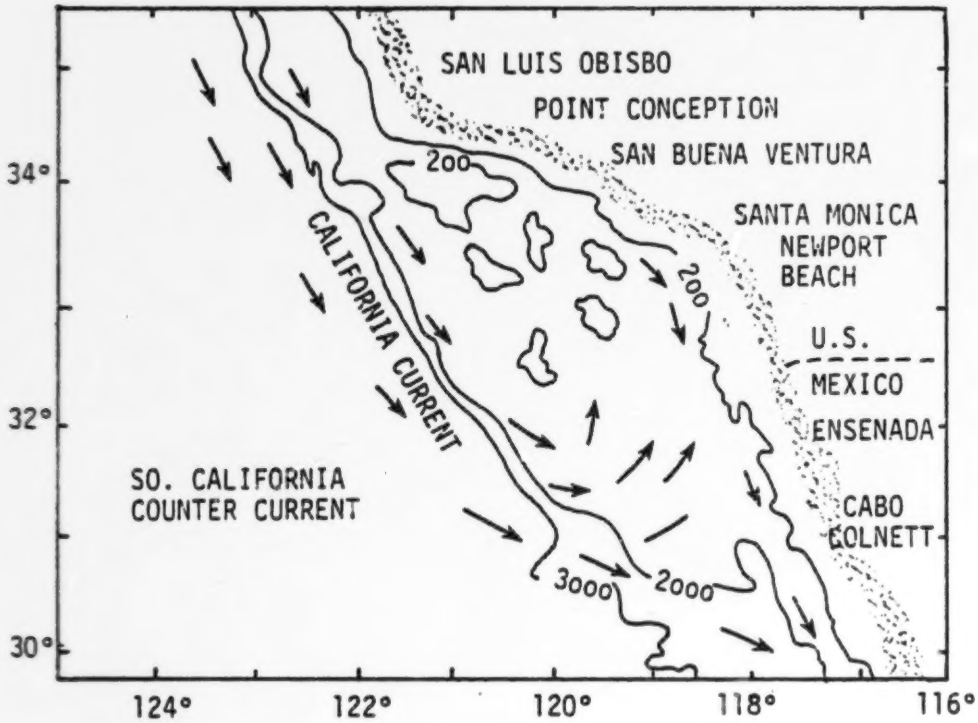
SAN LUIS OBISBO
POINT CONCEPTION
SAN BUENA VENTURA
SANTA MONICA
NEWPORT
BEACH
U.S.
MEXICO
ENSENADA
CABO
COLNETT
CALIFORNIA CURRENT
SO. CALIFORNIA
COUNTER CURRENT
200
200
3000
2000
34°
32°
30°
124°
122°
120°
118°
116°

Figure J-31. Generalized surface circulation (0-100 m) in the Southern California borderland area. (U.S. Department of the Interior, Final Environmental Statement, Vol. 1, Figure II-18, p. 134, from J.H. Jones, General Circulation and Water Characteristics in the Southern California Bight, Southern California Coastal Water Research Project, 1971.)

The nearshore currents measured over the continental shelf seaward of the surf zone appear to be dominated by the local wind, the tides, and the offshore geostrophic current direction.

Daytime current measurements at or near the surface record velocities in the range of 5 to 20 cm/sec, occasionally reaching 36 cm/sec (Allan Hancock Foundation, 1965). Currents commonly vary in direction up to 90° and sometimes as much as 180°. Maximum velocities over the mainland shelf occur anywhere from the surface to near the bottom. Usually the velocities are greatest at the surface, being about twice those 16 m below. Sewage and oil discharges which have a density less than local sea water float and will be influenced by the surface current direction and velocities. ...

The tidal heights along the Southern California coast range from about 30 cm to more than 2 m. The time between successive high (or low) tides varies from about 10 to 14 hours.

Off the coast of Southern California, the tide wave moves from the southeast to northwest, following the coastline at such a rate and incident angle that high tide reaches Point Conception about 1/2 hour after passing San Diego. Although the wave speed is nearly 400 km/hour, the associated motion of fluid particles (the tidal current) is a very small fraction of the wave speed (of the order of 20 cm/sec). ...

## Climate

The Southern California coastal and offshore area has a Mediterranean dry summer subtropical climate characterized by warm, dry summers and mild, wet winters. This is caused by the location of Southern California on the southeastern edge of the Pacific High Pressure Area (Pacific Subtropical Anticyclone). This high area forces most of the low fronts that develop to follow a course northward of the United States, bringing about a stable weather pattern that would not otherwise exist. In winter the Pacific Subtropical Anticyclone weakens, permitting the Aleutian Low (sea storms) to invade as early as October (U.S. Coast Pilot #7, 1968).

Prevailing winds along the Southern California Coast are generally from the northwest, flowing parallel with the coast and averaging 5 to 10 knots. As the coastline trends flow forward in an east-west direction, the winds shift to a west-southwest direction (U.S. Coast Pilot #7, 1968). Figure J-32 shows the annual average wind speed and direction for the offshore area.

Severe winds (>25 knots) occur primarily from the northwest, predominantly in the spring. In the fall and winter Santa Ana winds blow from the east and northeast. Some of the Channel islands are extremely vulnerable to these winds.

Inversions, created by subsiding air from the Pacific High Pressure Area, are common in the summer. Cool, stable marine air is trapped below a layer of warm, dry air. Natural particles and air pollutants are trapped in this cool air, causing a layer of haze to exist in the air.

## 2.2 Resources -- Description and Principal Uses

### Commercial Resources

The coastal and offshore waters of Southern California are extremely productive and support a very diverse marine flora and fauna. The Final EIS for the OCS Sale #35 contains thorough description of the biotic communities found along the coast. Here the focus is on the resources of most importance, the commercial species, rare or endangered species and special habitats.

> Commercial fishing in Southern California has largely consisted of pelagic wetfish and tunas. Pelagic wetfish include anchovies, sardines, mackerels and squid. The wetfish industry has both declined and changed in species composition. Following the decline of the sardine during the period 1945 to 1952, the anchovy became and is now the most important species in the wetfish industry. The anchovy, however, is not processed as wetfish but reduced to fish meal and oil and is low, although increasing, in price. According to Stephen's (1972) calculations from Frey's (1971) data, the wetfish industry is one-sixth as productive now as in 1936. The tuna catch, likewise, has greatly decreased in size for local waters, and according to Stephens (1972), is one-half as productive today as in 1936. Tuna fishing is now a worldwide operation, and most of the fish brought to Southern California are caught off Central and South America and West Africa. About 94% of the 1972 tuna catch was made outside of the California waters based on preliminary data compiled by Bell (1974).

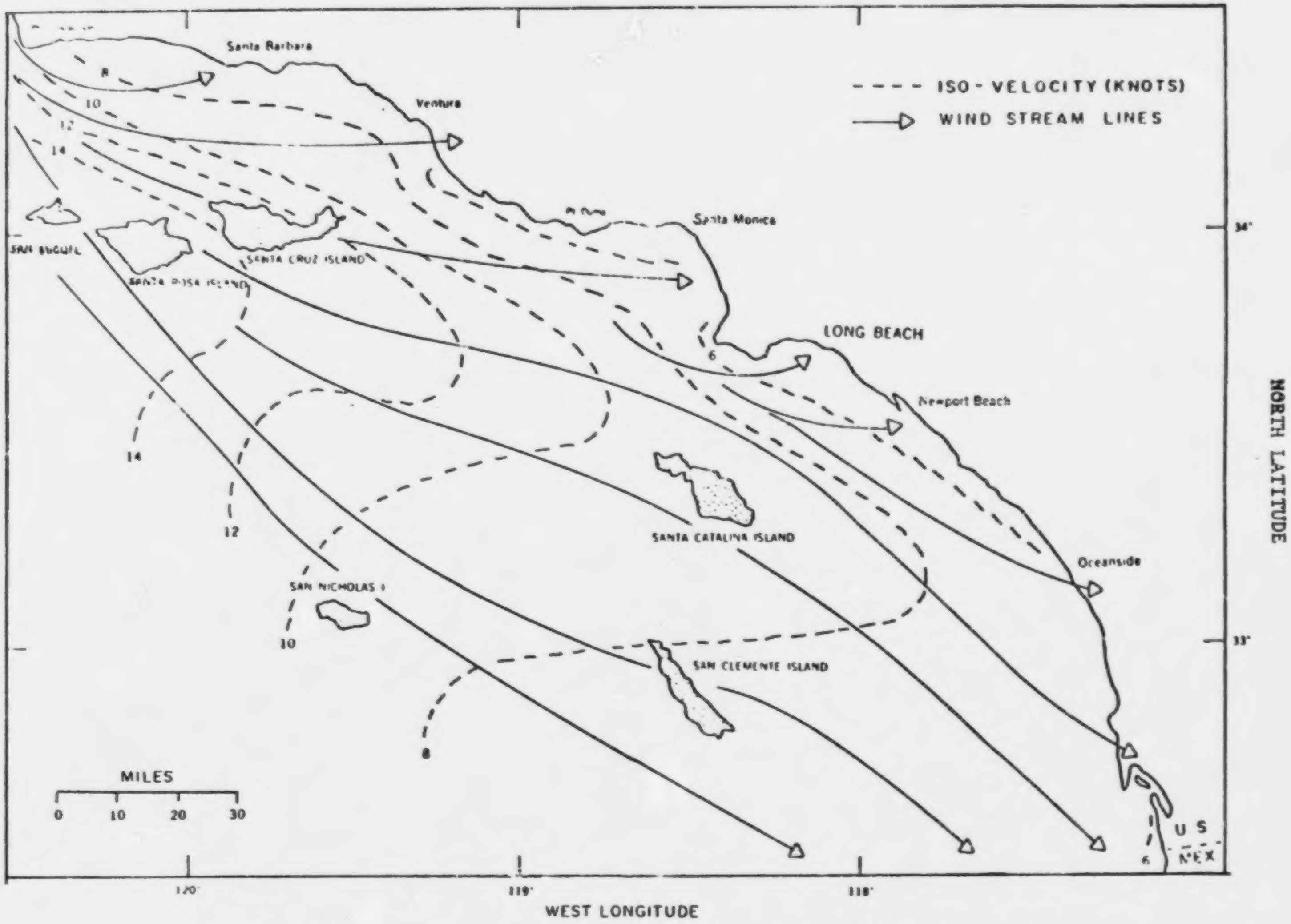
Santa Barbara
Ventura
Pt Dume
Santa Monica
LONG BEACH
Newport Beach
Oceanside
ISO - VELOCITY (KNOTS)
WIND STREAM LINES
SAN MIGUEL
SANTA ROSA ISLAND
SANTA CRUZ ISLAND
SANTA CATALINA ISLAND
SAN NICHOLAS I
SAN CLEMENTE ISLAND
8
10
12
14
14
12
10
8
6
6
MILES
0
10
20
30
U S
MEX
34
33
34°
33°
120°
119°
118°
WEST LONGITUDE
NORTH LATITUDE

Figure J-32. Annual average wind for offshore California. (U.S. Department of the Interior, Final Environmental Statement, OSC Sale No. 35, Vol. 1, from Allan Hancock Foundation, An Oceanographic and Biological Survey of the Southern California Mainland Shelf, California State Water Quality Control Baord, Pub. 27, 1965.)

The tunas: yellowfin tuna, skipjack tuna, Bluefin tuna, and Pacific bonito, dominate the list of California landings. Based on data presented by Oliphart and staff (1973), tunas comprised 63% of the weight and 83% of the value of all landings and shipments into California in 1971.

Numerous shellfish species are commercially important in Southern California. These include the spiny lobster (Panulirus interruptus), four species of abalone (Haliotis sp.), oysters, pismo, razor, gaper and Washington clams, rock crabs (three species), bay and brine shrimp and sand crabs. Shellfish contribute over $5 million annually to the California commercial fishery. Many of these shellfish are dependent on the estuaries, bays, and wetlands of the coast, which have been drastically reduced in number and size over the past 50 years.

A number of Southern California seaweeds are of economic value, though collection and processing costs have reduced the utilization of most species. A polysaccharide called algin is extracted from the giant kelp Macrocystis, which occurs in dense stands offshore. Algin is used as a thickening, stabilizing and emulsifying agent in many foods and other materials.

## Biologic Resources

Many of the biologic communities found in Southern California are particularly important for their aesthetic value, their sensitivity to environmental perturbation, or their support of economically valuable, rare or endangered species. Among such habitats are kelp beds, marshes, bays and estuaries, the Channel Islands, and the purple coral reefs. Table J-15 lists many of the rare and endangered species found in these coastal habitats.

Giant kelp beds are found in water to depths of 100 feet. The growth and reproduction of Macrocystis, the giant kelp, is limited by available light, temperature, rocky substrate, nutrients present, numbers of grazers such as sea urchins and abalone, disease, storms and thermal and sewage outflows. Aside from the economic value of the kelp plants themselves, the dense stands provide shelter, food and spawning sites for many fish and invertebrates.

## TABLE J-15

## ENDANGERED SPECIES OF CALIFORNIA

California Brown Pelican (*Pelecanus occidentalis californicus*)
Southern Bald Eagle (*Haliaeetus leucocephalus*)
California Condor (*Gymnogyps californianus*)
American Peregrine Falcon (*Falco peregrinus anatum*)
Light-Footed Clapper Rail (*Rallus longirostris levyses*)
California Least Tern (*Sterna albifrons browni*)
Belding's Savannah Sparrow (*Passerculus sandwichensis beldingi*)
Unarmored Threespine Stickleback (*Gastervsteus aculeatus williamsoni*)

Gray Whale (*Eschrichtius gibbosus*)
Blue Whale (*Balenoptera musculus*)
Finback Whale (*Balenoptera physalus*)
Sei Whale (*Balenoptera borealis*)
Humpback Whale (*Megaptera movreangliae*)
Pacific Right Whale (*Balena galcialis*)
Sperm Whale (*Physterer catodon*)

## RARE SPECIES

Island Fox (*Urocyon lattorallis*)
Guadalupe Fur Seal (*Arctocephalus philippii townsend*)
California Black Rail (*Laterallus samarcensis coturniculus*)

The Channel Islands, San Miguel, Santa Rosa, Santa Cruz, Anacapa, Santa Barbara, San Clemente, San Nicholas and Santa Catalina, are bound by deep basins and are 11 to 20 million years old. They are located astride a major break in the biogeography of the Pacific Coast, causing a change in species composition on the islands, ascribed primarily to ocean currents. These islands are important as homes for 18 endemic subspecies of terrestrial birds, as breeding and roosting sites for over 30 seabird species and as the only Brown Pelican rookery in California. The islands are also breeding sites for the elephant seal and California sea lion, house the only northern fur seal breeding colony south of Alaska, and are the only area north of Mexico still visited by the rare Guadalupe fur seal. The islands support 76 endemic and rare plants; the largest single stand of giant coreopsis (Coreopsis gigantea) and one of two living stands of torrey pine. They also have archeological value, containing remnants of 200 villages of the Canallion Indian culture.

A rare phenomenon of special note is the purple coral reefs (Allopoia california) on Farnsworth Bank off Santa Catalina Island. These areas have the only dense concentrated population in Southern California.

Southern California is notable for having coastal embayments and wetlands on a smaller scale than found at the same latitude on the Atlantic coast. This is due to the arid climate, recent geological settling and lack of large rivers entering the sea. The absence of a coastal plain has restricted the development of salt marsh to small areas fringing sheltered bays and lagoons.

The bays, lagoons and marshes support animals recruited from the sea. Neritic species such as the California halibut, the Pacific staghorn sculpin, the deepbody anchovy and the gray smoothound use these areas as nursery grounds. Other fish, the topsmelt, the California killfish, the arrow goby and the diamond turbot, complete their life cycle in the bays.

The population increase in Southern California has altered the natural state of these coastal habitats. Almost all of the bays and lagoons have been modified by activities such as construction of marinas and breakwaters, building of roads and railroads, dredging of channels, diversion of rivers and waste dispcsal operations. Alteration of the bays and wetlands has undoubtedly affected their support capacity and species composition, although no one knows to what extent this has occurred. These habitats are among the most valuable to the productivity of the California coast, and are extremely sensitive to changes in water quality and physiographic conditions.

### Population and Economy

Southern California's coastal counties from Santa Barbara to San Diego had an estimated population of 10,833,200 by July 1, 1974. This represents slightly more than one-half the populace of the entire state on less than nine percent of the land area. Southern California experienced approximately a one percent increase in population in 1973. This is the same rate of growth as experienced by California and the United States as a whole.

Table J-16 gives employment figures for the coastal counties of Southern California. Mining, which includes petroleum production, employs a relatively small percentage of the population.

## 2.3 Environmental Quality

### Air Quality

The State of California is divided into 11 air basins, composed of areas having similar meteorological and geographical conditions. Two of these basins are located within the Southern California offshore area: the South Coast Basin and the San Diego Basin. Table J-17 presents both the California and Federal Ambient Air Quality Standards. Table J-18 presents the number of above standard excursions recorded in the South Coast and San Diego Basin. In 1972 the South Coast Air Basin, which encompasses the Los Angeles Metropolitan Area, was responsible for almost half of all state emissions of organic gases, nitrogen oxides, carbon monoxide and sulfur dioxide.

A typical characteristic of air pollution in the Southern California coastal region is its oxidizing effect. This effect is due to the formation of ozone (and other photochemical oxidants such as PAN) in the atmosphere when reactions involving hydrocarbons and nitrogen oxides occur in the presence of sunlight. Meteorological factors such as temperature, stability, mixing height and wind speed affect the patterns of photochemical air pollution problems.

## TABLE J-16

## SOUTHERN CALIFORNIA COASTAL COUNTIES - LABOR MARKET TRENDS
SEPTEMBER 1972
(Thousands)

| | Los Angeles | Orange | San Diego | Ventura | Santa Barbara | Total |
|---|---|---|---|---|---|---|
| Total Civilian Labor Force | 3359.5 | 531.9 | 495.9 | 132.3 | 107.3 | 4626.9 |
| Unemployment | 171.5 | 26.1 | 26.1 | 6.6 | 5.3 | 235.6 |
| Unemployment Rate (Seas. Adj.) | 5.4 | 5.3 | 5.5 | 5.9 | 5.3 | |
| Total Civilian Employment | 3188.0 | 505.8 | 469.8 | 125.7 | 102.0 | 4391.3 |
| Non-Agriculture Wage/Salary | 2870.2 | 445.2+ | 411.6 | 100.1 | 83.4 | 3910.5 |
| Manufacturing | 789.6 | 121.4 | 57.9 | 14.1 | 9.6 | 992.8 |
| Durable Goods | 536.8 | 91.7 | 44.9 | 8.1 | 6.9 | 688.4 |
| Non-Durable Goods | 252.8 | 29.7 | 13.0 | 6.0 | 2.9 | 304.4 |
| Non-Manufacturing | 2080.6 | 323.8 | 353.7 | 86.0 | 73.6 | 2917.7 |
| Mining | 10.6 | 2.0 | .5 | 1.7 | .9 | 15.7 |
| Construction | 94.9 | 26.5 | 24.1 | 4.9 | 3.7 | 154.1 |
| Transportation/Utilities | 174.1 | 15.2 | 22.2 | 4.6 | 3.5 | 219.6 |
| Trade | 645.6 | 107.5 | 95.2 | 24.1 | 19.6 | 892.0 |
| Finance/Ins./Real Estate | 179.3 | 24.5 | 21.1 | 3.7 | 3.2 | 231.8 |
| Service | 544.5 | 77.7 | 84.0 | 16.2 | 21.2 | 743.6 |
| Government[a] | 431.6 | 70.4 | 106.6 | 30.8 | 21.5 | 660.9 |
| All Other Non-Agriculture Employment[b] | 307.9 | 52.5 | 47.2 | 11.9 | 12.5 | 432.0 |
| Agriculture Employment | 9.9 | 8.1 | 11.0 | 13.7 | 6.1 | 48.8 |

[a] Includes civilian employees of Federal, State and Local governments.
[b] Includes domestics, self-employed and unpaid family workers.

Source: State of California, Employment Development Department

TABLE J-17

## AMBIENT AIR QUALITY STANDARDS APPLICABLE IN CALIFORNIA

| Pollutant | Averaging Time | California Standards Concentration | Federal Standards | |
|---|---|---|---|---|
| | | | Primary | Secondary |
| Photochemical Oxidants (Corrected for $NO_2$) | 1 Hour | 0.10ppm | 0.08ppm | Same as Primary Standard |
| Carbon Monoxide | 12 Hours | 10ppm | - | Same as Primary Standard |
| | 8 Hours | - | 9 ppm | |
| | 1 Hour | 40ppm | 35ppm | |
| Nitrogen Dioxide | Annual Average | - | 0.05ppm | |
| | 1 Hour | 0.25ppm | - | Same as Primary Standard |
| Sulphur Dioxide | Annual Average | - | 0.03ppm | 0.02ppm |
| | 24 Hours | 0.04ppm | 0.14ppm | 0.10ppm |
| | 3 Hours | - | - | 0.5ppm |
| | 1 Hour | 0.5ppm | - | - |
| Suspended Particulate Matter | Annual Geometric Mean | 60 | 75 | 60 |
| | 24 Hours | 100 | 260 | 150 |
| Lead (Particulate) | 30 Day Average | 1.5 | - | - |
| Hydrogen Sulfide | 1 Hour | 0.03ppm | - | - |
| Hydrocarbons (Corrected for Methane) | 3 Hours | - | 0.24ppm | Same as Primary Standard |
| Visibility Reducing Particles | 1 Observation | Visibility to less than 10 miles when the relative humidity is less than 70 percent | - | - |

Source: State of California Resources Agency-Air Resources Board. Air Pollution in California, Annual Report 1972, pg.4.

## TABLE J-18

## MAXIMUM POLLUTANT CONCENTRATIONS OBSERVED IN 1970 OF SOUTHERN CALIFORNIA COASTAL AIR BASINS

| Air Basins | Carbon Monoxide | Nitrogen Dioxide | Oxidant | Particulate Matter | Sulfur Dioxide |
|---|---|---|---|---|---|
| | 8 Hr. Average ppm | Annual Average ppm | 1 Hr. Average ppm | AGM* - ug/m$^3$ | Annual Average ppm |
| Nat'l. Primary Standards | 9 | .05 | .08 | 75 | .03 |
| Nat'l. Secondary Standards | 9 | .05 | .08 | 60 | .02 |
| North Coast | - | - | - | 104 | Less than .01 |
| Bay Area | 13 | .05 | .30 | 84 | Less than .01 |
| North Central Coast | 6 | .02 | .11 | 67 | - |
| South Central Coast | 7 | .02 | .12 | 72 | - |
| South Coast | 41 | .09 | .62 | 127 | .03 |
| Northeast Plateau | - | - | - | - | - |
| Sacramento Valley | 22 | .03 | .24 | 57 | Less than .01 |
| San Joaquin Valley | 15 | .05 | .21 | 169 | Less than .01 |
| Great Basin Valley | - | - | - | - | - |
| Southeast Desert | 12 | - | .46 | 128 | - |
| San Diego | 16 | .03 | .40 | 87 | Less than .01 |

*Annual Geometric Mean

Source: State of California, Resources Agency - Air Resource Board, Air Pollution in California, Annual Report 1972, p.16.

## Water Quality

> Marine water pollution within the Southern California Bight area is mainly of terrestrial origin. ...The largest single source is municipal waste waters discharged directly into the ocean from twenty-five outfalls between Point Conception and the Mexican Border.
>
> In addition to 25 (SCCWRP, 1973) municipal waste treatment plants which discharge directly into the marine coastal waters there are an additional eighty-three plants which discharge onto the land or water courses and may be considered as contributing ultimately to marine pollution.
>
> Other sources of pollution originate from industrial processes, pollution from electric generating plants, terrestrial runoff, offshore dumping, serial fallout, dredging and day to day use of the marine environment by the public.
>
> Industrial wastes are the second largest source of pollution (SCCWRP, 1973). The SCCWRP report notes with the exception of one industrial plant the entire industrial (non power) waste discharge into marine waters is from petroleum-related industries (oil brine, tanker ballast, refinery waste). This includes onshore and offshore oil production, transport, processing and oil tanker mooring facilities.
>
> These direct ocean industrial dischargers are grouped in three main areas, Santa Barbara channel, Santa Monica Bay, and the northern coast of Orange County. Direct ocean discharge of industrial wastes into the bight area contributes about 6% of the total suspended solids, 14% of the total oil and grease, 2% of the total biochemical oxygen demand, and 10% of the total chemical oxygen demand. ...

Inputs of petroleum from terrestrial sources are mainly from municipal wastewaters, industrial wastewaters and surface runoff. A comparison of the estimated mass emission rates from these sources is given in Table J-19.

TABLE J-19

SOURCES OF OIL AND GREASE/PETROLEUM DISCHARGED INTO THE SOUTHERN CALIFORNIA MARINE ENVIRONMENT

| SOURCE | MASS EMISSION RATES (METRIC TONS/YR) OIL AND GREASE | PETROLEUM |
|---|---|---|
| Municipal wastewaters | 65,000 | 32,000 |
| Industrial wastewaters | 2,200 | 2,200 |
| Runoff | 4,400 | ? |

Source: Storrs, 1973.

As indicated in Table J-19 municipal wastewaters contribute large amounts of oil and grease (hexane-extractable), of which approximately 50 percent is petroleum. Young (1975) indicates that it has been tentatively estimated that such wastewaters may contribute up to 10 percent of the total known input of petroleum hydrocarbons to the world oceans.

Although industrial wastewaters are shown to discharge less petroleum than municipal dischargers, it is noted that petroleum industries contribute most of the petroleum to the municipal wastes.

From Storrs (1973) it is indicated that the petroleum refining capacity in Southern California is about 400 million barrels (bbls) per year, or about 10 percent of the total United States refinery capacity. Table J-20 shows the results of a recent survey of oil discharged to the Southern California coastal waters from the petroleum industry (SCCWRP, 1973).

Of the 2,200 metric tons per year discharged to the nearshore waters, approximately 80 percent is due to oil in refinery wastewaters. The remaining 20 percent is due to operations of both the onshore and offshore production facilities. In the Southern California area, the offshore production capacity is about 9.7 million bbls/yr. Thus, in terms of refinery capacity, the Southern California oil discharges are about 5 metric tons per million barrels (Storrs, 1973).

Table J-20

OIL DISCHARGES FROM THE PETROLEUM INDUSTRY TO SOUTHERN CALIFORNIA COASTAL WATERS

| Wastewater Type | Wastewater Flow (cu m/s) | Mass Emission Rate (metric tons/yr) |
|---|---|---|
| Oil field brines | 1.75 | 380 |
| Tanker and line ballast | 0.35 | 65 |
| Refinery wastewaters | 4.72 | 1,740 |
| Cooling tower bleedoff | 0.03 | 10 |
| | | 2,200 |

The source of oil in runoff areas is from urban storm drainage, runoff from rural areas, and natural stream drainage. The percentage of petroleum in these waters is unknown.

Another source of oil is natural oil seeps. Young (1975) indicates that estimates of petroleum losses to the water column from the 50-60 known natural oil seeps between Point Conception and Huntington Beach appear to be relatively uncertain, although four seep sites at Coal Oil Point near Santa Barbara are reported to have lost the equivalent of 4000 metric tons/year during October, 1969. However, such seepage rates are reported to be quite variable. In comparison, estimates for the 1969 Santa Barbara oil spill range from 3000 to 113,000 metric tons, with an intermediate value of about 11,000 tons....

Terrestrial surface runoff constitutes the third and last "discrete" (SCCWRP, 1973) source of pollution in the Bight area. There are 200-300 major rivers, streams and storm drains (SCCWRP, 1973) which yearly introduce a wide spectrum of solids, trace metals, chemicals, organic nutrients and hydrocarbons into the marine environment. Surface runoff is seasonal, being the greatest during winter months.

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## 3. Texas

### 3.1 Physiography and Climate

#### Physiography

Texas is part of four major physiographic subdivisions of North America -- the Gulf Coastal Forested Plains, the Great Western Lower Plains, the Great Western High Plains, and the Rocky Mountain Region. The state is topographically a series of plains. There are three major plains divisions from the northwestern part of the state to the Gulf -- the Staked Plains, the North Central Plains, and the Gulf Coastal Plain.

The Staked Plains reach an elevation of about 4,000 feet above sea level. The High Plains area of this region is characteristically level in land surface, relatively treeless, and semiarid. The topography of the North Central Plains is level to rolling and shows a typical prairie environment, with the occurrence of timber increasing to the east. The Gulf Coastal Plain rises from sea level to around 550 feet above sea level; the topography is rolling to hilly. The climate becomes increasingly arid to the west, resulting in treeless prairies.

#### Climate

The climate of Texas is marked by extremes in temperature, precipitation rates, and the variation and extent of catastrophic weather events which affect all regions of the state. The climatic patterns of the state are determined primarily by the interaction of moisture-laden Gulf air masses moving northwestward over the state and dryer, relatively cooler air masses moving southeastward from the continental interior. Texas suffers frequent occurrences of hail, floods, tornados and hurricanes, as well as recurrent droughts.

Precipitation in Texas is poorly distributed in space as well as time. Average annual precipitation ranges from 8 inches (El Paso) to 55 inches (Port Arthur). In general,

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Note: All information in this section (unless otherwise footnoted) was taken from: Texas Water Development Board, *The Texas Water Plan*, November 1968.

there is an average increase from west to east of about 1 inch of precipitation every 15.5 miles. Texas experiences abnormally wet and dry years.

Texas winds range from the Gulf coast sea breezes to the west Texas duststorms. Although the latter are a rare occurrence, this part of Texas is characterized by more frequent high-wind episodes than the rest of the state. The active sea breeze regime characteristically penetrates about 25 miles inland. In spite of the variety of wind regimes present, the annual mean wind speeds across the state only vary from about 4 meters per second at San Antonio to just over 6 meters per second at Amarillo. Data on the wind speed distributions at various stations reveal a significant difference between northern and southern sections. About 6 percent of the hourly winds recorded in northern Texas fall into the lowest wind speed class (less than 1.5 meters per second), while 11 percent of those reported in southern Texas fall into this class. The standard deviation associated with interstation variability is 2.5 percent and 4.6 percent for the two respective regions. This tends to indicate that southern Texas, including the coast, is subject to a large number of air stagnation episodes.

## 3.2 Population and Economy

### Population

The population of Texas has greatly increased during the past century, with centers of concentration shifting from a predominantly agricultural economy to a more balanced agricultural, industrial, and commercial economy. Census figures from 1960 indicated a total state population of 9.6 million; projections for 1980 and 2000 are 15 and 21.2 million, respectively. In 1960, about 75 percent of the people lived in urban areas; 23 principal urban areas held about 67 percent of the total population.

### Economy

The Texas economy has been broadened by the vast expansion of the petroleum products industry. Petrochemical production is the fastest growing of all the industries in Texas. The scale of manufacturing in Texas has increased rapidly; value added to the economy by manufacturing between 1949 and 1963 increased nearly fourfold, and is expected to total $40.9 billion by 1990. Broad-based industrial development has contributed to the rapid expansion of trades and services to support employees as well as plants. Transportation, utilities, and construction activities have burgeoned as well.

Despite the trend toward urbanization, farms and commercial forest holdings in 1965 occupied over 90 percent of the total surface area of Texas. Much of the industrial economy and employment in Texas' cities is wholly or partially dependent on agriculture. These industrial sectors include the food and allied products industries; agricultural supplies, materials, equipment and services; food, crop, and livestock product processing; and agricultural chemicals, transportation and marketing. These agriculturally-oriented segments constitute a multibillion dollar contribution to the annual total economy of the state. Agriculture generates more of Texas' wealth, supporting a related annual $6 billion to $7 billion commerce and industry, than any other factor in the economy with the exception of petroleum and petrochemicals.

## 3.3 Resources

### Land

Texas has been divided into the 10 ecological regions shown in Figure J-33. Livestock grazing is a major land use in Regions 1, 2, 3, 5, 6, 7, 8, and 10. Cropping is a principal land use in six areas; grain and cotton constitute the major crops in Regions 2, 3, 4, 6, 8, and 9. Irrigated cropping is common in the High Plains and, to a limited extent, in the South Texas Plains. Industrial and urban land use are greatest in the Gulf Prairies and Marshes and the Cross Timbers and Prairies regions respectively. Commercial forestry is the dominant land use in the Pineywoods.[1]

### Surface Water

Figure J-34 illustrates the average annual precipitation, streamflow and net lake surface evaporation of the major rivers in Texas. About three-fourths of the nearly 40 million acre-feet of average annual runoff originates in the eastern quarter of Texas. Annual averages range from about 1,100 acre-feet per square mile in the east to practically zero for much of west Texas. Though evaporation rates are high

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[1] Texas Parks and Wildlife Department, Strategies for Texas Wildlife Resources, Vol. 1, September 1975, pp. 4-5.

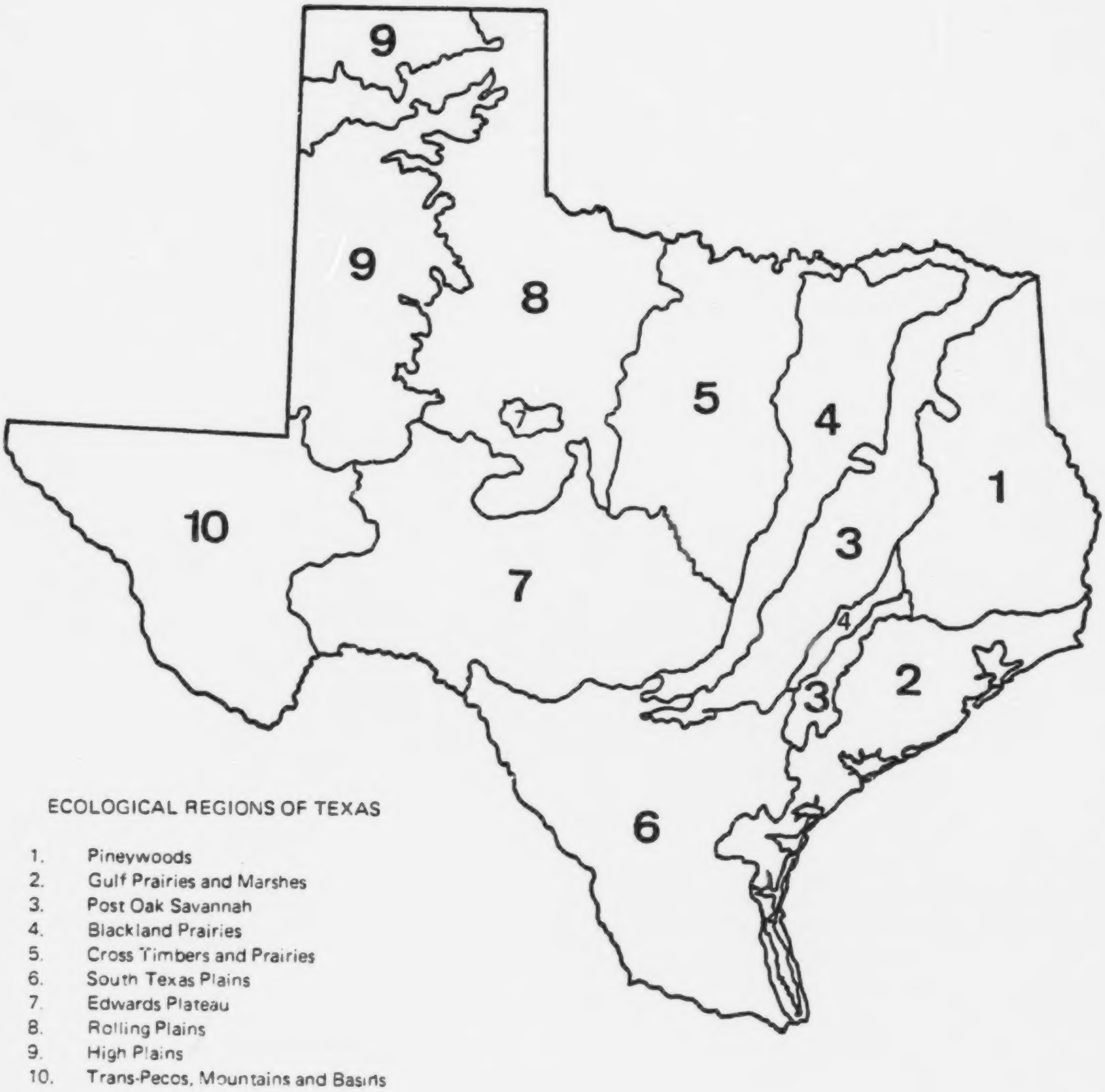
9
9
8
5
4
1
3
10
7
4
2
3
6
7
ECOLOGICAL REGIONS OF TEXAS
1. Pineywoods
2. Gulf Prairies and Marshes
3. Post Oak Savannah
4. Blackland Prairies
5. Cross Timbers and Prairies
6. South Texas Plains
7. Edwards Plateau
8. Rolling Plains
9. High Plains
10. Trans-Pecos, Mountains and Basins

Figure J-33. Ecological regions of Texas. (Texas Parks and Wildlife Department, Strategies for Texas Wildlife Reserves, September 1, 1975, p. 5.)

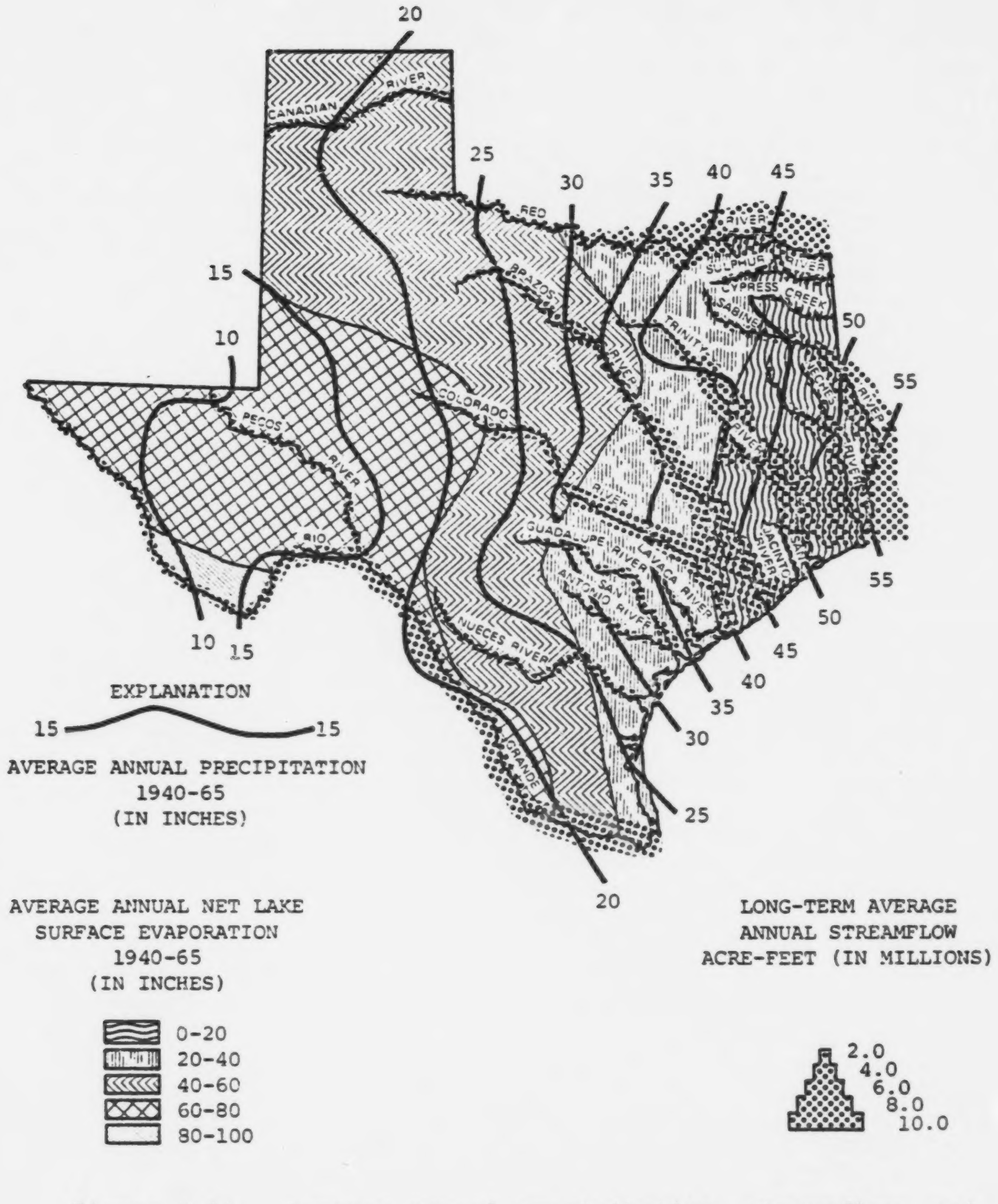
20
25
30
35
40
45
50
55
15
10
CANADIAN RIVER
RED RIVER
BRAZOS RIVER
SULPHUR RIVER
CYPRESS CREEK
SABINE RIVER
TRINITY RIVER
NECHES RIVER
COLORADO RIVER
PECOS RIVER
RIO GRANDE
GUADALUPE RIVER
LAVACA RIVER
SAN ANTONIO RIVER
SAN JACINTO RIVER
NUECES RIVER
EXPLANATION
15 15
AVERAGE ANNUAL PRECIPITATION 1940-65 (IN INCHES)
AVERAGE ANNUAL NET LAKE SURFACE EVAPORATION 1940-65 (IN INCHES)
0-20
20-40
40-60
60-80
80-100
LONG-TERM AVERAGE ANNUAL STREAMFLOW ACRE-FEET (IN MILLIONS)
2.0
4.0
6.0
8.0
10.0

Figure J-34. Average annual precipitation, streamflow, and net lake surface evaporation. (Texas Water Development Board, The Texas Water Plan, November 1968, Figure II-8, p. 11-17.)

throughout Texas they are particularly high in the dry central and western portions of the state as illustrated in Figure J-34. This figure clearly demonstrates the limits of surface water supplies in that important oil-producing region.

Surface water is used for navigation, municipal and industrial requirements, and irrigation. At present, groundwater aquifers supply the bulk of the water used in Texas; it is expected, however, that as ground aquifer resources are depleted, more water will be drawn from surface water supplies.

Ground Water

In 1970, groundwater aquifers supplied about 67 percent of the water used in Texas.[2] In the past, municipalities, industry, irrigators, and rural inhabitants have made use of this resource for several reasons. Aquifers are of widespread geographical occurrence, surface water supplies are either insufficient or poorly distributed, and the costs of developing and pumping ground water are low compared to costs of constructing storage and treatment facilities for surface water supplies.

A major aquifer has been defined by the Texas Water Development Board as one which yields large quantities of water in a comparatively large area of the state. There are seven major aquifers in Texas, as shown in Figure J-35. Collectively, these aquifers supply most of the ground water used in the state. They include the Ogallala Aquifer, Alluvium Aquifer, Edwards-Trinity (Plateau) Aquifer, Edwards (Balcones Fault Zone) Aquifer, Trinity Group Aquifer, Carrigo-Wilcox Aquifer, and the Gulf Coast Aquifer.

Many of these aquifers have been subject to intensive development for irrigation, municipal and industrial use, and mining. Depletion and intrusion of saline water are constraints in many of these areas. More ground water is being removed in many areas of the state than is being replaced by natural recharge. The Gulf Coast Aquifer has the brightest prospects of continuing to furnish adequate quantities of water to meet projected needs; yet even in this aquifer, there is a problem of land subsidence due to

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[2] U.S. Environmental Protection Agency, Office of Research and Monitoring, Ground Water Pollution in the South Central States, EPA-R2-73-268, June 1973, p. 7.

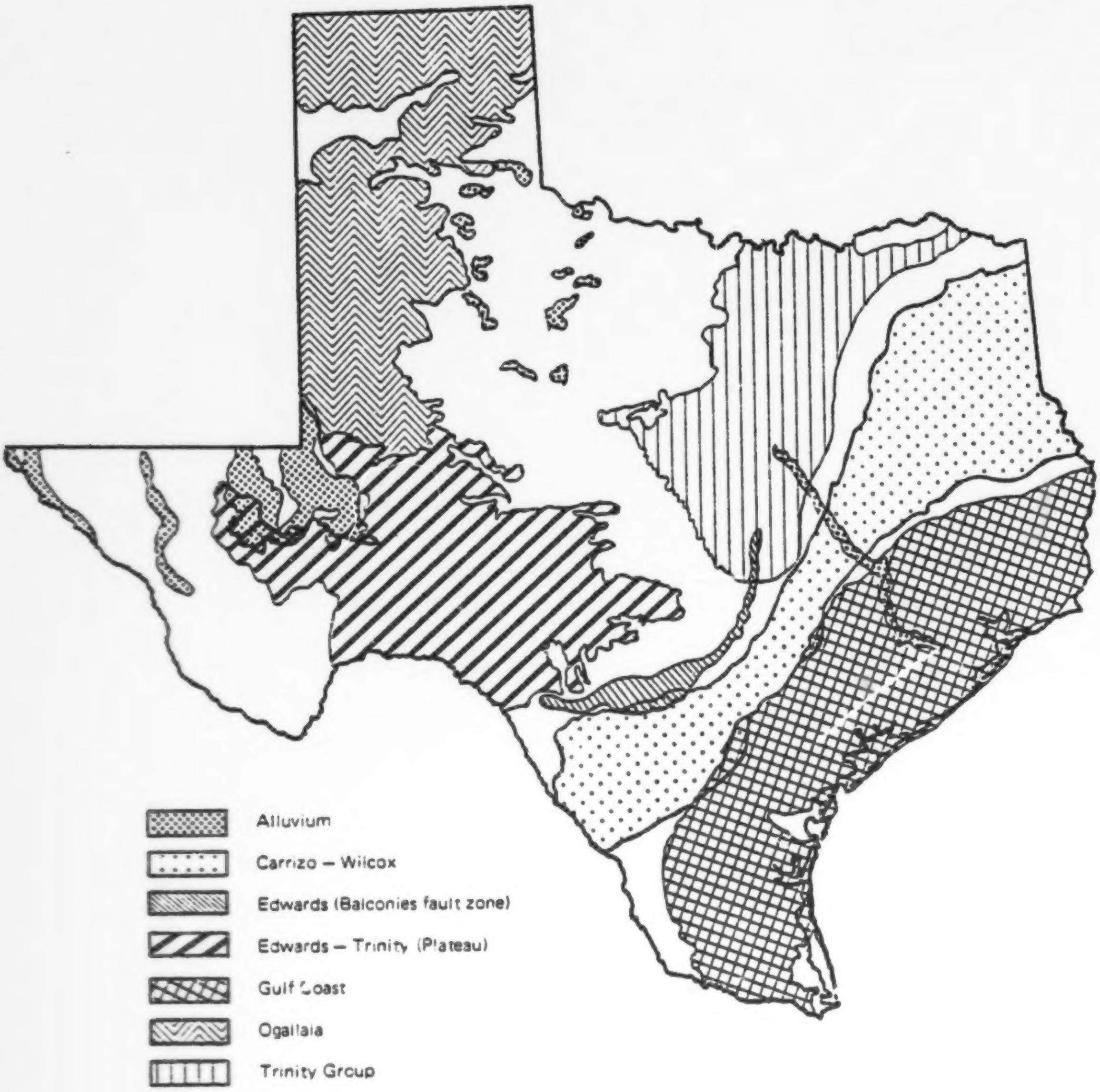
Alluvium
Carrizo – Wilcox
Edwards (Balconies fault zone)
Edwards – Trinity (Plateau)
Gulf Coast
Ogallala
Trinity Group

Figure J-35. Major aquifers of Texas. (Texas Water Development Board, The Texas Water Plan, November 1968, Figure II-2, p. II-5.)

pumping, particularly in the Baytown-Pasadena area and along the Houston Ship Channel. Other major aquifers are limited in the amount of good quality water they can supply for expanding needs (see Figure J-35). Nearly 83 percent of all present irrigation in Texas is supplied by ground water.

The minor aquifers in Texas (see Figure J-36) are important and in some areas the only sources of water supply. In most cases their capacity for large-scale use is limited.

## Wildlife and Recreation

A wide range of environmental conditions in coastal bays and estuaries and the warm Gulf waters off the Texas coast have provided highly productive conditions for wildlife and aquatic life of commercial and recreational significance. These are discussed in Section J.B.1.

Inland fishing is a popular and lucrative Texan sport. Ducks, geese, wild turkey, quail, and doves attract many hunters. Deer and pronghorn antelope are the principal game animals. Wildlife management is an important concern; 21 established national and state wildlife and migratory waterfowl refuges, game preserves, and wildlife management areas have helped to maintain favorable conditions for sustaining increased wildlife development in Texas.

## Energy

Electrical energy used in Texas is presently derived from two sources, fossil fuel generating plants and hydroelectric generating facilities. In 1974, steam-electric (thermal) plants furnished over 99 percent of the total energy demand, while hydroelectric plants, presently utilized for peaking power purposes, supplied the remainder.[3,4] Natural gas provided 90 percent of the fossil power in 1975.

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[3] Federal Power Commission, Statistics of Privately-Owned Electric Utilities in the U.S., 1974, pp. 723-724.

[4] Federal Power Commission, Statistics of Publicly-Owned Electric Utilities in the U.S., 1974, pp. 53A-55A.

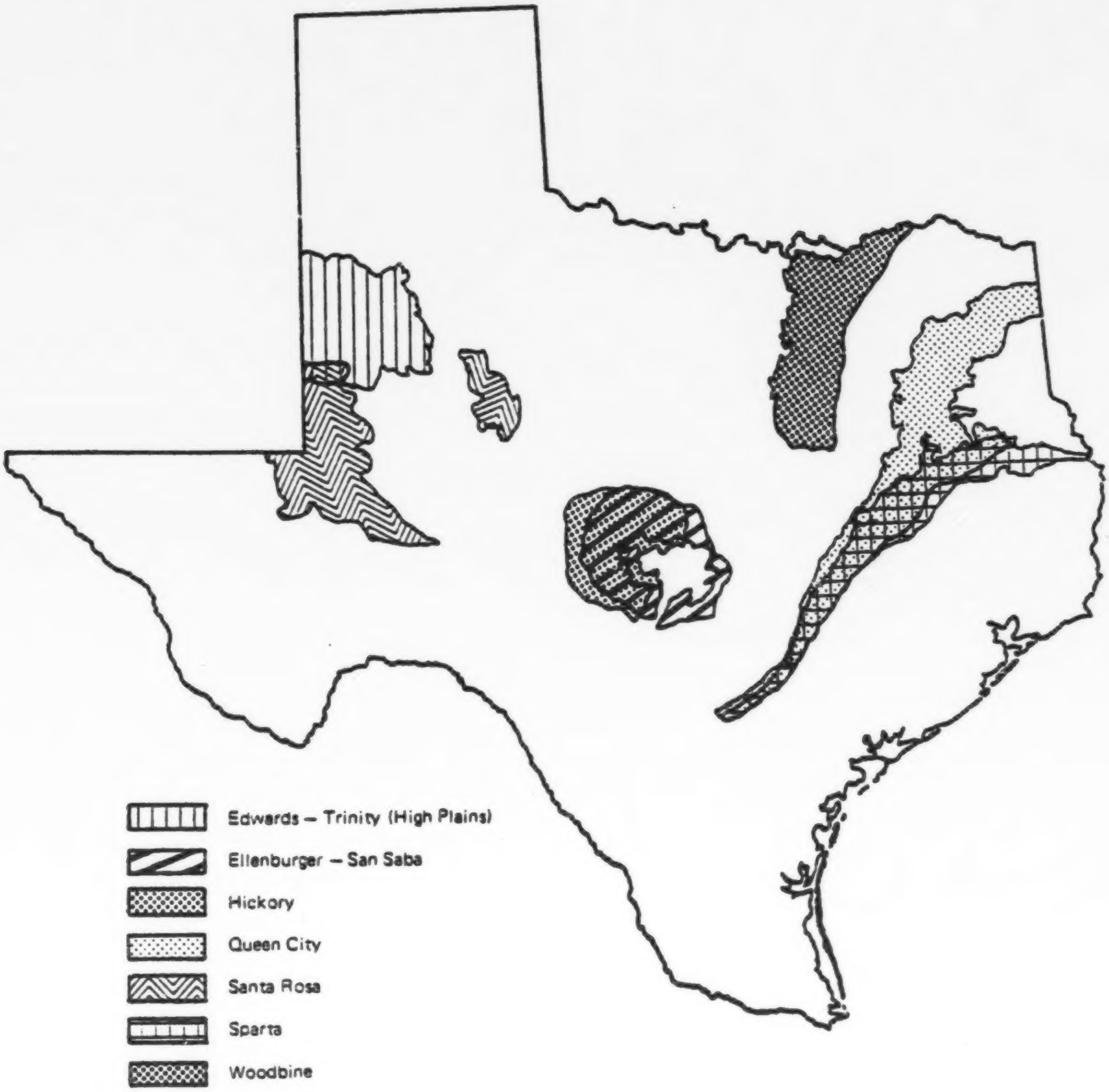

Edwards – Trinity (High Plains)
Ellenburger – San Saba
Hickory
Queen City
Santa Rosa
Sparta
Woodbine

Figure J-36. Minor aquifers of Texas. (Texas Water Development Board, The Texas Water Plan, November 1968, Figure II-7, p. II-12.)

## 3.4 Environmental Quality

### Air Quality

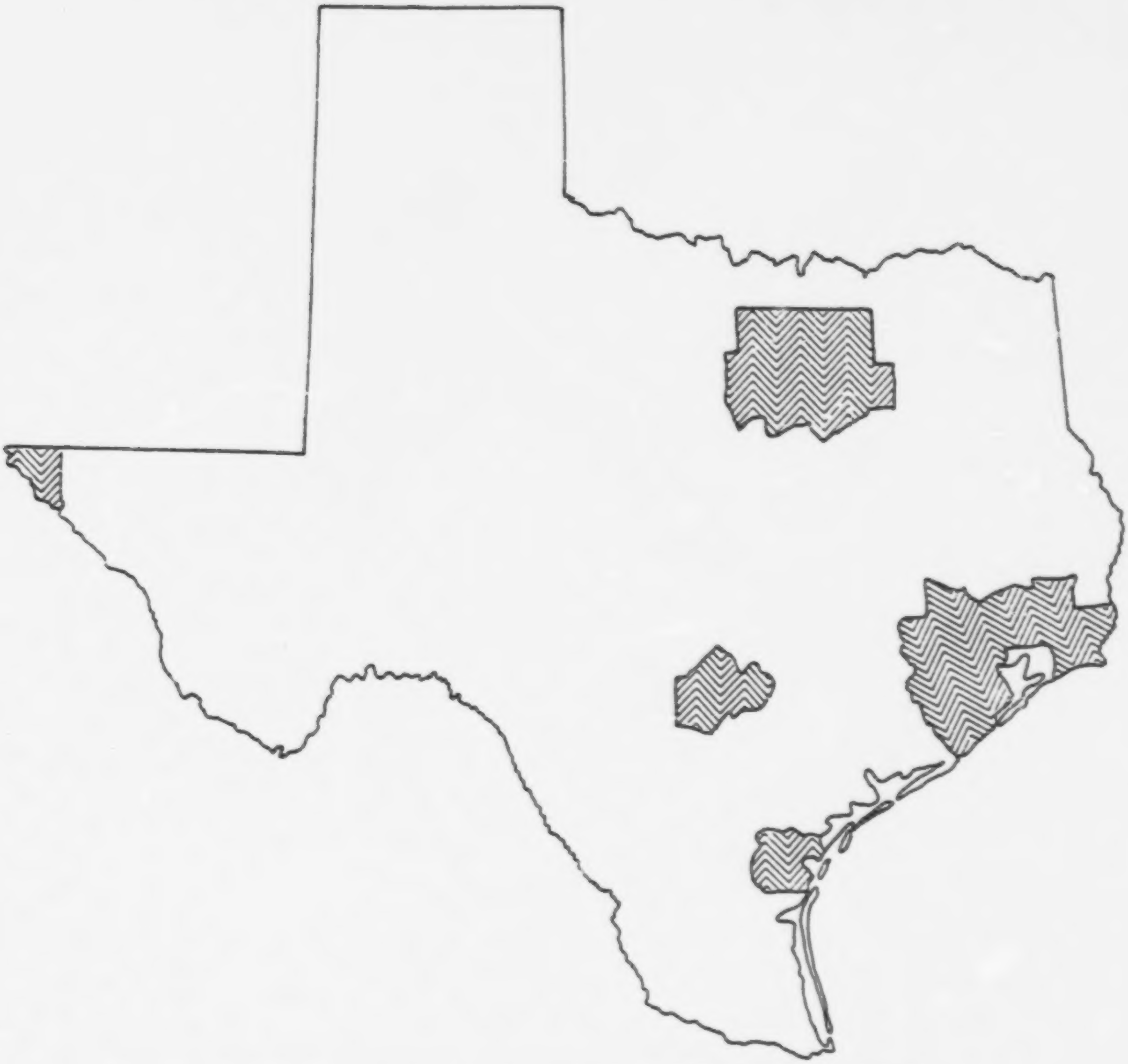
Seven areas in Texas have been designated Air Quality Maintenance Areas or Regions; six of these areas coincide with regions where tertiary oil production techniques are technically feasible. They include Beaumont, Corpus Christi, Dallas-Ft. Worth, Galveston, Houston and San Antonio. These areas have been noted primarily for their high levels of particulate matter and photochemical oxidants. Galveston is the only AQMA in which $SO_2$ is a problem (see Figure J-37). The estimated status of attainment of air quality standards in 1975 is listed for each AQCR in Table J-21. Evidently, much of the particulate problem arises from sources of fugitive dust emissions. The status of all criteria pollutants in 1974 is contained in Table J-22. This provides some indication of the magnitude of the violations by indicating which standards were violated, and how many of the active monitors were affected. The Texas air quality standards are listed in Table J-13.

### Surface Water Quality

The quality of surface water varies widely across the state. Total dissolved solids concentrations range from under 100 to over 3,000 mg/l, with around 100 to 500 mg/l in most river reaches. The higher concentrations are most common in the sediment-laden regions of western and central Texas where sediment buildup in reservoirs is also a problem. Inorganic pollutants from natural and man-made sources probably constitute more of a widespread problem than organic materials from municipal and industrial wastes. Three river basins, the Trinity, San Jacinto and Rio Grande, have a serious sanitary quality problem. Part of the Texas Water Plan for improving water quality assumes the elimination of pollution resulting from oilfield brines.

### Groundwater Quality

Ground water from the various major aquifers in the state varies widely in concentration of dissolved solids, with values ranging from 300 to 3,000 mg/l. In many areas where heavy pumping has occurred, land subsidence and intrusion of saline water have become significant problems. Intrusion of saline water into the Gulf Coast Aquifer has occurred in the Galveston, Baytown, and Texas City areas and



| AQMA | AQMA Number | POLLUTANTS | | | | |
|---|---|---|---|---|---|---|
| | | PM | $SO_2$ | CO | $O_X$ | $NO_2$ |
| Texas | | | | | | |
| Beaumont | 106A | X | | | X | |
| Corpus Christi | 214A | X | | | | |
| Dallas-Ft. Worth | 215A | X | | | X | |
| El Paso | 153B | | | | X | |
| Galveston | 216A | X | X | | X | |
| Houston | 216B | X | | | X | |
| San Antonio | 217A | | | | X | |

Figure J-37. Texas Air Quality Maintenance Areas. (U.S. Environmental Protection Agency, Guidelines for Air Quality Maintenance Planning and Analysis, Volume 14: Designated Air Quality Maintenance Areas, December 1975, Figure 45, p. 154.)

## TABLE J-21

## ESTIMATED ATTAINMENT OF NATIONAL TSP AND $SO_2$ AMBIENT AIR QUALITY STANDARDS BY AIR QUALITY CONTROL REGION[1]

## (TEXAS)

| AQCR | Probably will attain | Probably will not attain | Attainment status uncertain |
|---|---|---|---|
| *022. Shreveport-Texarkana-Tyler Interstate (Ark., La., Okla.) | TSP[2]<br>$SO_2$ | | |
| *106. Southern Louisiana-Southeast Texas Interstate (La.) | TSP[2]<br>$SO_2$ | | |
| *153. El Paso-Las Cruces-Alamogordo Interstate (New Mexico) | $SO_2$ | TSP Fugitive dust area | |
| 210. Abilene-Wichita Falls | $SO_2$ | TSP Fugitive dust area | |
| 211. Amarillo-Lubbock | $SO_2$ | TSP Fugitive dust area | |
| 212. Austin-Waco | TSP<br>$SO_2$ | | |
| 213. Brownsville-Laredo | $SO_2$ | TSP Fugitive dust area | |
| 214. Corpus Christi-Victoria | $SO_2$ | TSP Fugitive dust area & non-point sources | |
| 215. Metropolitan Dallas-Fort Worth | $SO_2$ | TSP - Non-point sources | |
| 216. Metropolitan Houston-Galveston | | TSP - Non-point sources<br>$SO_2$ - Point sources | |
| 217. Metropolitan San Antonio | $SO_2$ | TSP Fugitive dust area | |
| 218. Midland-Odessa-San Angelo | TSP<br>$SO_2$ | | |

* = Interstate AQCR

[1] Attainment is based on most recent air quality data available; these do not, in all cases, reflect final compliance. Estimated attainment status for both TSP (total suspended particulate) and $SO_2$ (sulfur dioxide) is based on annual and/or 24-hour averages. Comments noting factors that prevent attainment are occasionally included in the last two columns; these comments, like the attainment status, are best estimates and/or judgements.

[2] Estimated attainment status for this pollutant is different in another State portion of this interstate AQCR.

## TABLE J-22

## NUMBER OF STATIONS REPORTING AND NUMBER OF STATIONS AT WHICH STANDARDS WERE EXCEEDED, BY AQCR, 1970-1974

(TEXAS)

| AIR QUALITY CONTROL REGION | YR | SUSPENDED PARTICULATES ANNUAL # STA (1) | # > SEC 60 | # > PRI 75 | 24-HOUR # STA (2) | # > SEC 150 | # > PRI 260 | SULFUR DIOXIDE ANNUAL # STA (1) | # > STD 80 .03 | 24-HR # STA (2) | # > STD 365 .14 | 3-HR # > STD 1300 .50 | CARBON MONOXIDE # STA (2) | 1-HR # > STD 40* 35 | 8-HR # > STD 10* 9 | OXIDANTS # STA (2) | 1-HR # > STD 160 .08 | NITROGEN DIOXIDE # STA (1) | # >ANN STD 100 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| UG/CU.M) |  |  | 60 | 75 |  | 150 | 260 |  | 80 |  | 365 | 1300 |  | 40* | 10* |  | 160 |  | 100 |
| P.P.M) |  |  | - | - |  | - | - |  | .03 |  | .14 | .50 |  | 35 | 9 |  | .08 |  |  |
| 153 EL PASO-LAS CRUCES-ALAMOGORDO (N.MEX-TEX) |  | ( 7) |  |  |  |  |  | ( 5 + 2) |  |  |  |  | ( 2) |  |  | ( 2) |  | ( 0) |  |
|  | 70 | 9 | 4 | 3 | 4 | 3 | 3 | 1 | 0 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
|  | 71 | 6 | 6 | 6 | 16 | 19 | 9 | 0 | 0 | 1 | 0 | 0 | 0 | 0 | 0 | 3 | 0 | 0 | 0 |
|  | 72 | 2 | 2 | 2 | 19 | 16 | 13 | 0 | 0 | 2 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
|  | 73 | 22 | 19 | 19 | 32 | 25 | 13 | 4 | 0 | 13 | 0 | 0 | 3 | 0 | 3 | 0 | 0 | 0 | 0 |
|  | 74 | 10 | 6 | 2 | 37 | 20 | 4 | 6 | 0 | 17 | 0 | 0 | 3 | 0 | 2 | 4 | 3 | 2 | 0 |
| 210 ABILENE-WICHITA FALLS (TEX) |  | ( 3) |  |  |  |  |  | ( 3 + 1) |  |  |  |  | ( 0) |  |  | ( 0) |  | ( 0) |  |
|  | 70 | 0 | ? | ? | 2 | 1 | 1 | 0 | 0 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
|  | 71 | 1 | 1 | 0 | 3 | 0 | 0 | 0 | 0 | 2 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
|  | 72 | 2 | 1 | 1 | 3 | 2 | 0 | 1 | 0 | 3 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
|  | 73 | 2 | 2 | 1 | 4 | 2 | 0 | 2 | 0 | 4 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
|  | 74 | 0 | ? | 0 | 4 | 0 | 0 | 1 | 0 | 4 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 0 |
| 211 AMARILLO-LUBBOCK (TEX) |  | ( 3) |  |  |  |  |  | ( 6 + 2) |  |  |  |  | ( 0) |  |  | ( 0) |  | ( 0) |  |
|  | 70 | 1 | 1 | 1 | 5 | 3 | 0 | 0 | 0 | 2 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
|  | 71 | 17 | 16 | 16 | 22 | 19 | 15 | 0 | 0 | 3 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
|  | 72 | 10 | 7 | 4 | 23 | 20 | 13 | 2 | 0 | 7 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
|  | 73 | 2 | 1 | 1 | 20 | 11 | 1 | 2 | 0 | 7 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
|  | 74 | 0 | ? | ? | 5 | 2 | 1 | 1 | 0 | 5 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 0 |
| 212 AUSTIN-WACO (TEX) |  | ( 3) |  |  |  |  |  | ( 1 + 0) |  |  |  |  | ( 0) |  |  | ( 3) |  | ( 0) |  |
|  | 70 | 2 | 2 | 0 | 3 | 0 | 0 | 1 | 0 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
|  | 71 | 1 | ? | 0 | 6 | 1 | 0 | 0 | 0 | 2 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
|  | 72 | 5 | 3 | ? | 10 | 1 | 0 | [illegible] | 0 | 4 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
|  | 73 | ? | 3 | 2 | 12 | 3 | 0 | 2 | 0 | 7 | 0 | 0 | 0 | 0 | 0 | 2 | 2 | 0 | 0 |
|  | 74 | 0 | ? | 0 | 17 | 1 | 0 | 0 | 0 | 8 | 0 | 0 | 1 | 0 | 0 | 1 | 1 | 0 | 0 |
| 213 BROWNSVILLE-LAREDO (TEX) |  | ( 7) |  |  |  |  |  | ( 1 + 0) |  |  |  |  | ( 0) |  |  | ( 0) |  | ( 0) |  |
|  | 70 | 3 | 3 | 3 | 4 | 3 | 2 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
|  | 71 | 3 | 3 | 2 | 16 | 15 | 10 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
|  | 72 | 7 | 6 | 6 | 19 | 9 | 7 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
|  | 73 | 3 | 3 | 2 | 4 | 3 | 2 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
|  | 74 | 0 | ? | ? | 5 | 3 | 1 | 0 | 0 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

(1) NUMBER OF STATIONS REPORTING A FULL YEAR'S VALID DATA
(2) NUMBER OF STATIONS REPORTING AT LEAST 3 24-HR VALUES OR 400 HOURLY VALUES
? STATIONS WITH INCOMPLETE DATA MAY BE EXCEEDING THE ANNUAL STANDARD: SEE APPENDICES
* CO STANDARDS ARE IN MILLIGRAMS PER CUBIC METER

threatens other areas of concentrated pumpage along the coast. In areas of the Alluvium Aquifer, salinity has increased to the point that the water has become unsuitable for domestic or municipal use. In parts of the Trinity Group and the Carrizo-Wilcox Aquifers, improper well-completion methods and failure of well casings have allowed saline water in overlying beds to enter the freshwater-bearing zones. Intensive pumping should be avoided, particularly during drought periods, to insure adequate pressure and guard against saline water intrusion.

## 4. California

### 4.1 Physiography and Climate

California can be divided into four major physical regions: the Intermontane region, the Central Valley, and the Coastal and Sierra Nevada mountain ranges. The Central Valley region divides the Pacific Ranges into Coastal and Sierra Nevada ranges; the intermontane areas are located in the desert areas of the extreme southeast and south.[1] Approximate mean elevation is 2,900 feet above sea level and ranges from -282 to 14,494 feet.[2]

Southern California can be further subdivided into four physiographic provinces: the peninsular ranges, the transverse ranges, the Salton trough, and the Mojave Desert (see Figure J-38). The peninsular range extends from south of the Santa Monica mountains to south of the Mexican border and is topographically similar to the coast range with common elevations of 3,000 to 4,000 feet. A longitudinal valley is found in this province with a northwest-southeast trend. The Transverse Range Province is oriented in an east-west direction and is a series of mountain ranges and valleys, including the lowlands of the San Bernardino and Los Angeles plains of the east as well as the San Bernardino and San Gabriel mountains.[3] Land surface form in the Mojave Desert Province is predominantly lowland with some low mountains; the Salton trough province is principally smooth lowland plains.[4]

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[1] U. S. Department of the Interior, Geological Survey, National Atlas of the United States, 1970.

[2] U.S. Bureau of the Census, Statistical Abstracts of the United States, 1975, 96th Edition, 1975.

[3] U S. Department of the Interior, Bureau of Land Management, Final Environmental Statement, Proposed 1974 Outer Continental Shelf Oil and Gas General Lease Sale Offshore Southern California, OCS Sale No. 35, Vol. 4, 1975.

[4] U.S. Department of the Interior, National Atlas.

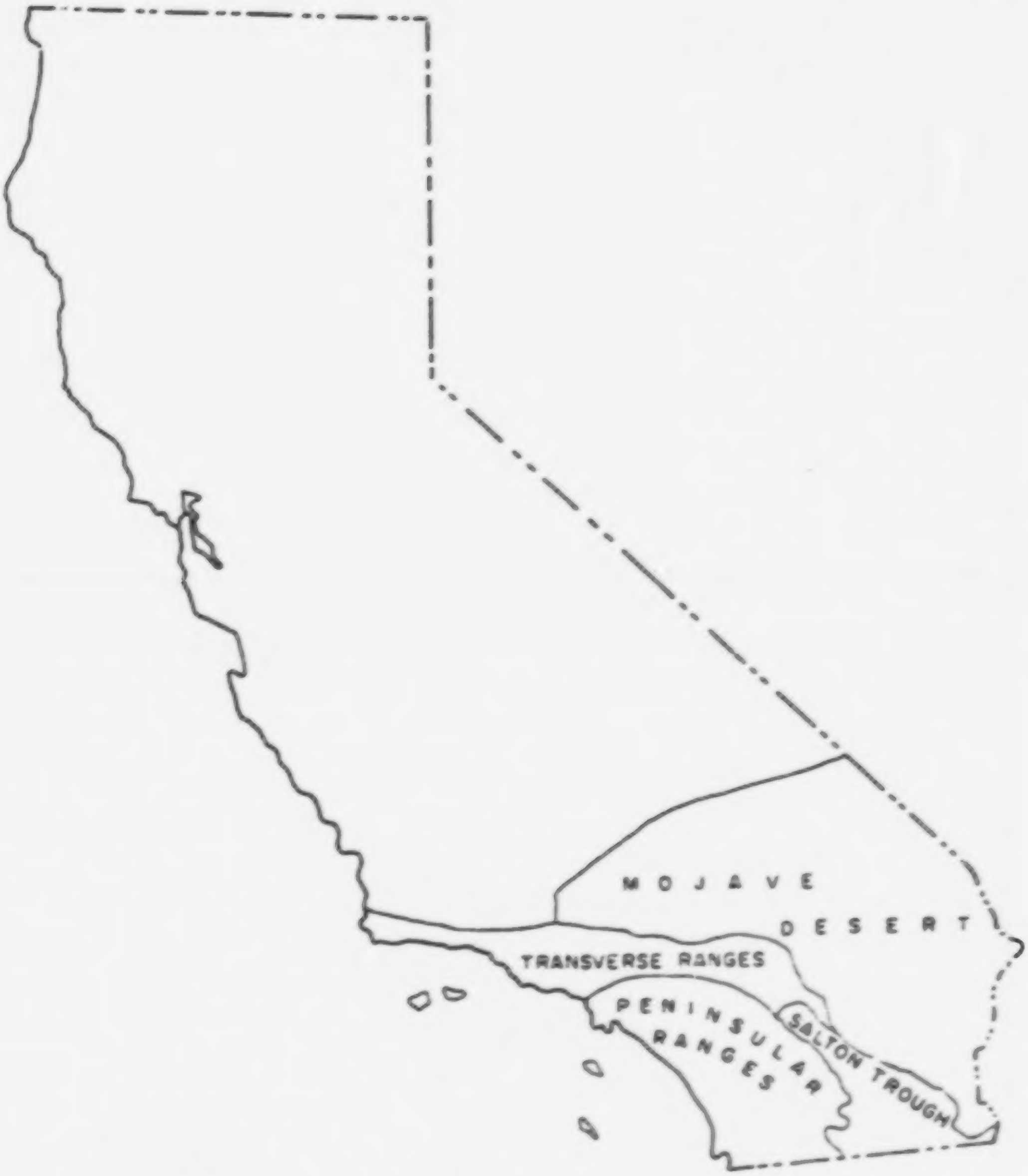
MOJAVE
DESERT
TRANSVERSE RANGES
PENINSULAR
RANGES
SALTON TROUGH

Figure J-38. Physiographic provinces of California. (U.S. Department of the Interior, Bureau of Land Management, 1975 Outer Continental Shelf Oil and Gas General Lease Sale Offshore Southern California, Vol. I, Figure II-1, p. 66, from California Division of Mines and Geology.)

## Climate[5]

Wide ranges in altitude and latitude are responsible in part for the variety of climates found in California. Another significant factor is the continuous interaction of maritime air masses with those of continental origin. Pronounced climatic changes occur within short distances as a result of these influences.

Summer is a dry period over most of the state due to the northward migration of the semipermanent Pacific high which deflects most storms to the far north. In winter, the Pacific high decreases in intensity and drops further south, permitting storms to move into and across the state, producing widespread rain at low elevations and snow at high elevations.

Annual precipitation totals in excess of 50 inches per year are characteristic of the west slope of the Sierra Nevada north of Stockton, the west slope of the coast range from Monterey County northward, and parts of the Cascades. Exceptions to this are totals of about 20 inches in the Monterey and San Francisco Bay areas. In the lee of the coast range yearly amounts drop off to 15 inches in parts of the Sacramento Valley and to less than 8 inches over most of the San Joaquin Valley. The northeast interior portion of the state receives from 15 to 18 inches of moisture in a year. In the mountains of Southern California, annual totals reach 30 to 40 inches, while the coastal plain receives only 10 to 15 inches. The desert of the southeast receives as little as 2 to 5 inches a year.

> California lies within the zone of prevailing westerlies and on the east side of the semipermanent high pressure area of the northeast Pacific Ocean. The basic flow in the free air above the State, therefore, is from the west or northwest during most of the year. The several mountain chains within the State, however, are responsible

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[5] Officials of the National Oceanic and Atmospheric Administration, U.S. Department of Commerce, *Climates of the United States, Volume II, Western States, Including Alaska and Hawaii* (Port Washington, N.Y.: Water Information Center, Inc. 1974).

Note: All indented material is quoted directly from the reference cited for the section in which it is written.

for deflecting these winds and, except for the immediate coast, wind direction is likely to be more a product of local terrain than it is of prevailing circulation.

In the Los Angeles area, however, the Basin is almost completely enclosed by mountains on the north and east. Coupled with this is a characteristic of the air along most of the coastal area of California. The vertical temperature structure tends to prevent vertical mixing of polluted air through more than a shallow layer (1,000 to 2,000 feet deep). The geographical configuration and the southerly location of the Basin permit a fairly regular daily reversal of wind direction--offshore at night and onshore during the day. With the concentrated population and industry, pollution products tend to accumulate in this circulation pattern.

Figures J-39 and J-40 show the predominant circulation of surface wind patterns for January and July. Low wind speeds (those in the range of 0 to 1.5 meters per second) occur relatively frequently in Southern and Central California. Approximately 19 percent of all hourly observed wind speeds in this region fall into this range. Variations among coastal stations produced a standard deviation of 6 percent, while the inland variations were responsible for a standard deviation of 11 percent. This indicates the importance of orographic influences away from the shore areas. Low wind speeds coupled with temperature inversions tend to promote air pollution episodes in the California basins.

## 4.2 Population and Economy

### Population[6]

In 1974, California's estimated population was 20.9 million. The coastal counties of Santa Barbara, Ventura, Los Angeles, Orange, and San Diego contributed nearly 52 percent of the total state population. Especially striking

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[6] Bureau of Census, Statistical Abstracts of the United States, 1975.

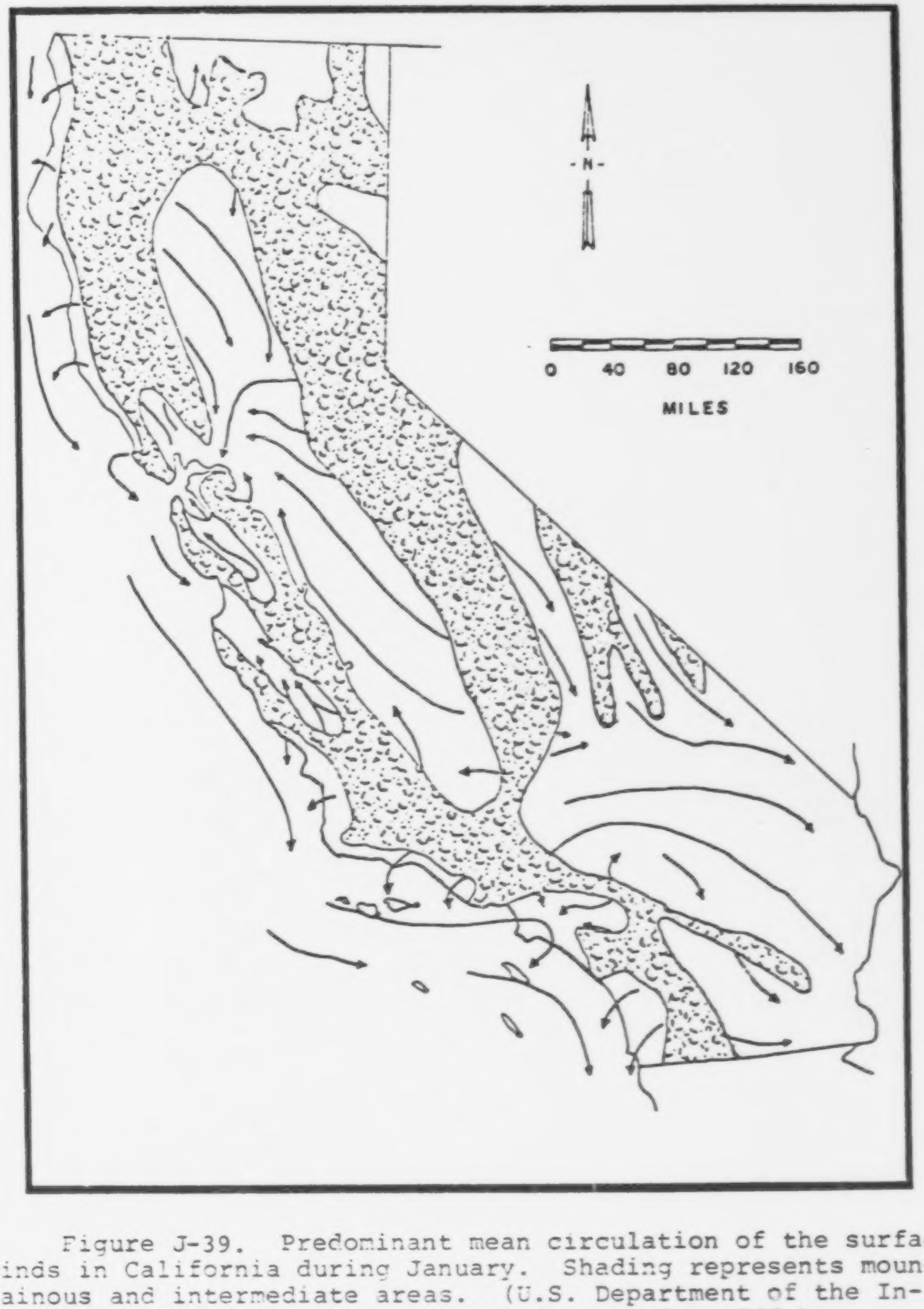

Figure J-39. Predominant mean circulation of the surface winds in California during January. Shading represents mountainous and intermediate areas. (U.S. Department of the Interior, 1975 Outer Continental Shelf Lease Sale Offshore Southern California, Vol. I, Figure II-10, p. 115, from Battelle Pacific Northwest Laboratories, 1973.)

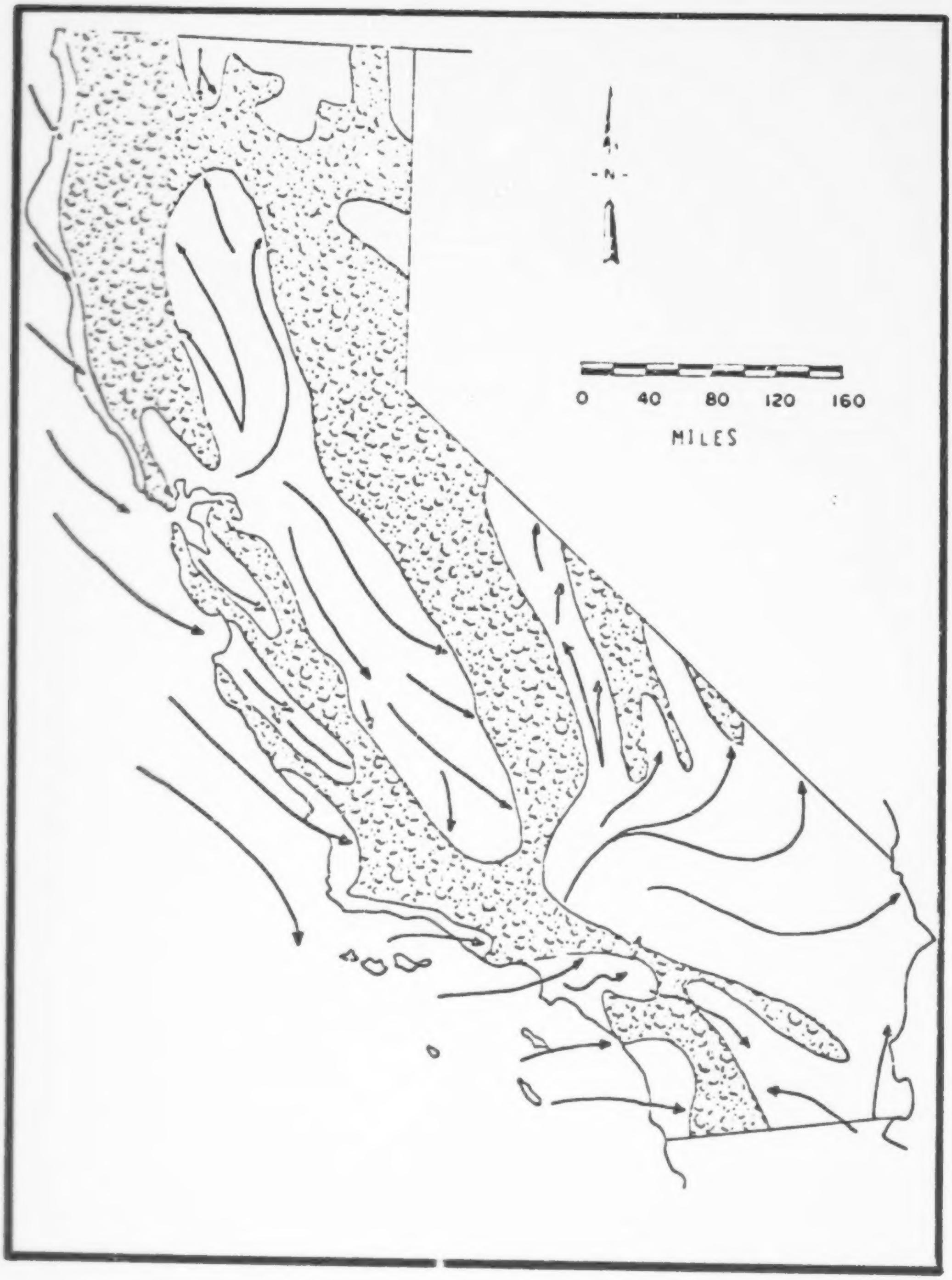

Figure J-40. Predominant mean circulation of the surface winds in California during July. Shading represents mountainous and intermediate areas. (U.S. Department of the Interior, *1975 Outer Continental Shelf Lease Sale Offshore Southern California*, Vol. I, Figure II-9, p. 114, from Battelle Pacific Northwest Laboratories, 1973.)

is the fact that these counties represent less than 9 percent of the land area in the state.[7] The San Francisco Bay Area is also densely populated, with 4.6 million people in 1972.

California is extensively urbanized; in 1970, nearly 91 percent of the population dwelt in urban areas. The population per square mile of land area, 127.6, is consequently misleading. In 1970, 93.4 percent of the population was contained in Standard Metropolitan Statistical Areas.

In 1974, the work force in California totaled 9,043,000, of which 7.7 percent were unemployed. Non-farm employment accounted for about 86.6 percent of the total work force; manufacturing and trade employed respectively 21.6 and 22.5 percent of the total state employment in non-farm enterprises. Service establishments accounted for 19.6 percent of the non-agricultural employees. In 1970, the California farm population numbered 249,000. 1968 figures show the majority of farmworkers were hired; only 28.6 percent were family workers.

### Economy[8]

In 1972, California ranked first in the nation in value added by manufacture with $31.2 billion. More than 35,700 establishments employed 1.5 million people with a total payroll of $15.5 billion. Transportation equipment, food, and electrical equipment were the leading major industry groups in value added by manufacture. The value of shipments in 1972 was $62.9 billion.

In 1974, California's farm marketings were $8.2 billion, making it number one in the nation. Crops accounted for $5.5 billion, or about 67 percent of all farm marketings. Livestock and products contributed the balance of $2.7 billion. The importance of agriculture to the California economy is apparent upon considering that California farms and other agriculture-related industries, such as food processing, financing of farm production, and sales of equipment and supplies to farms, generate income estimated to be at least $20 billion annually.[9]

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[7] Bureau of Land Management, Final Environmental Statement, OCS Sale No. 35.

[8] Bureau of Census, Statistical Abstracts of the United States, 1975.

In 1969, there were 77,875 farms in California on about 35.7 percent of the land. More than half of the farms fall between 50 and 1,000 acres; the average size is 459 acres. Agriculture is practiced most extensively in the Sacramento and San Joaquin Valleys of the Central Valley. At present, nearly 9 million of the 10.5 million acres of cultivated lands in California are irrigated.

Principal farm commodities in order of 1974 cash receipts were cattle, milk, cotton, and grapes. Principal crops in order of value were grapes, cotton lint, hay, and tomatoes. Of the more than 54 thousand farms with sales exceeding $2,500, nearly 44 percent were classified as fruit and nut producing.

## 4.3 Resources[10]

### Land

California can be grossly divided into four biomes -- grassland, desert, woodland-bushland, and coniferous forest. The grassland biome of the state is the Central Valley. Both subtypes of the desert biome are found in California; the cold desert type is found in the northeast, and the hot desert (the Mojave Desert) extends through southeastern California. The woodland-bushland biome forms a transitional zone between the grassland and desert biomes and the coniferous forest biome. The latter covers major areas in the Sierra Mountains and in the northwestern portion of the state.

The Federal government owns 44.8 percent of the land in California. Farmland comprises 35.7 percent. About 8 percent is commercial timberland. Total urban acreage in

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[9] State of California, The Resources Agency, The California Water Plan, Outlook in 1974, Department of Water Resources Buleetin No. 160-74, November 1974.

[10] Department of the Interior, Final Environmental Statement for the Geothermal Leasing Program, Vol. 1, 1973.

1972 was 2,645,000 acres or about 2.6 percent of the state's land area.[11]

California has a large share of U.S. oil reserves. Figure J-41 illustrates the location of oil fields in Southern California, where the bulk of oil production occurs. Tertiary recovery processes are either currently underway or technically feasible in the following counties: Fresno, Kern, Ventura, Santa Barbara, Monterey, Orange, San Luis Obispo, Los Angeles, and Kings. Oil wells are also located on the outer continental shelf of Southern California.

### Surface Water[12]

About 60 percent of California's present water supply is derived from regulation and diversion of the natural runoff from surface streams. Average annual runoff varies tremendously from one part of the state to another, ranging from 0.2 million acre-feet in the Colorado Desert hydrologic area to 27.2 million acre-feet in the North Coastal region. On the average, the total natural surface water supply of 71 million acre-feet in California is adequate to meet foreseeable demands. Unfortunately, natural stream runoff is not evenly distributed in place or time. Most of the state's runoff is in the northern portion; about 75 percent occurs north of Sacramento while about 75 percent of the demand for irrigation and urban water is south of Sacramento. Most of the rainfall and runoff occurs in the winter, while the peak demand for water supply occurs in the summer. This has necessitated the development of large-scale transfer systems involving the storage and transportation of water almost the entire length of the state.

Figure J-42 illustrates the major surface water supply and conveyance facilities in California in 1974. There are 16 major river basins in California that are usually divided into 11 hydrological areas for study purposes. Of particular interest to this analysis are the Colorado Desert, South Coastal, South Lahontan, Tulare Basin, and Central Coastal regions since oil-producing activities are found principally in these areas.

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[11] Bureau of Census, Statistical Abstracts of the United States, 1975.

[12] State of California, The Resources Agency, California Water Plan, Outlook in 1974.

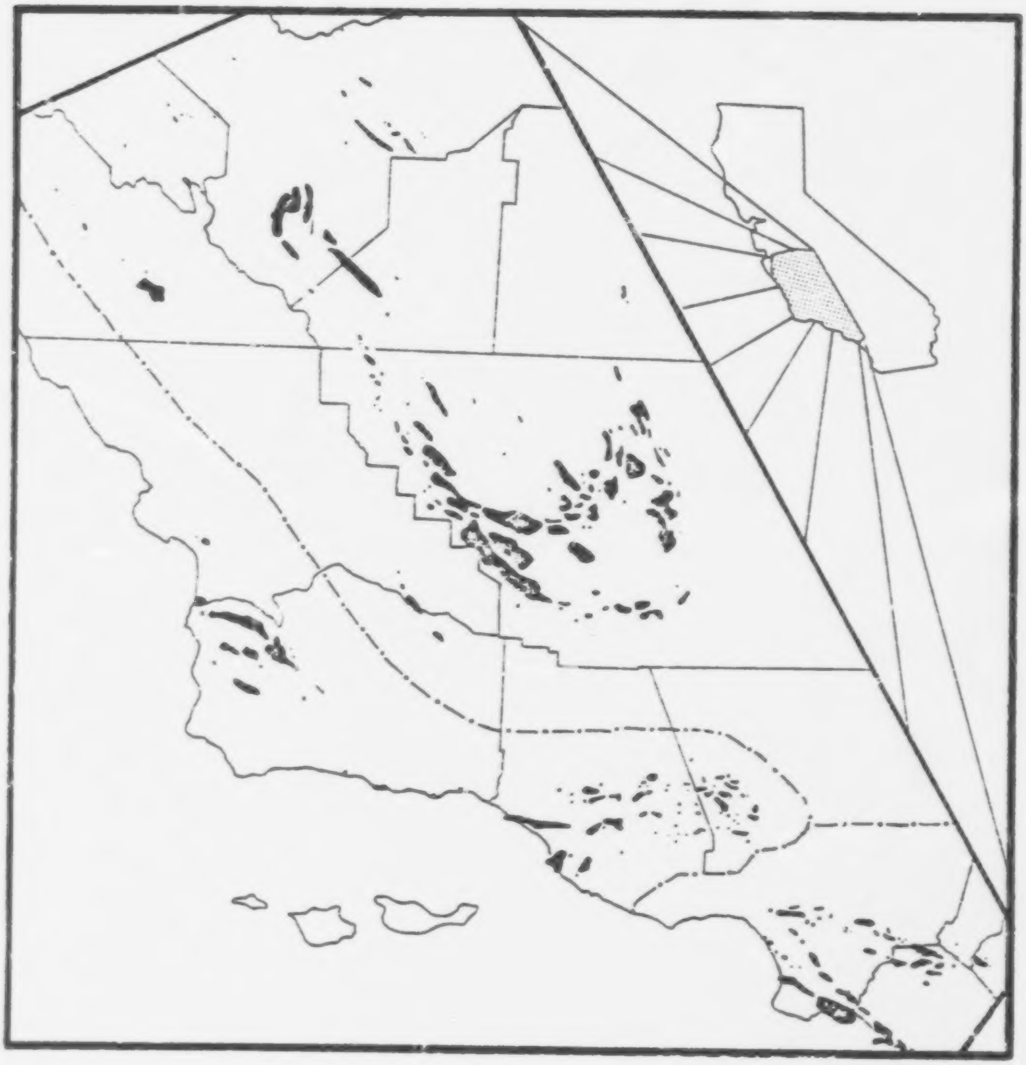

Figure J-41. Oil fields in Southern California.

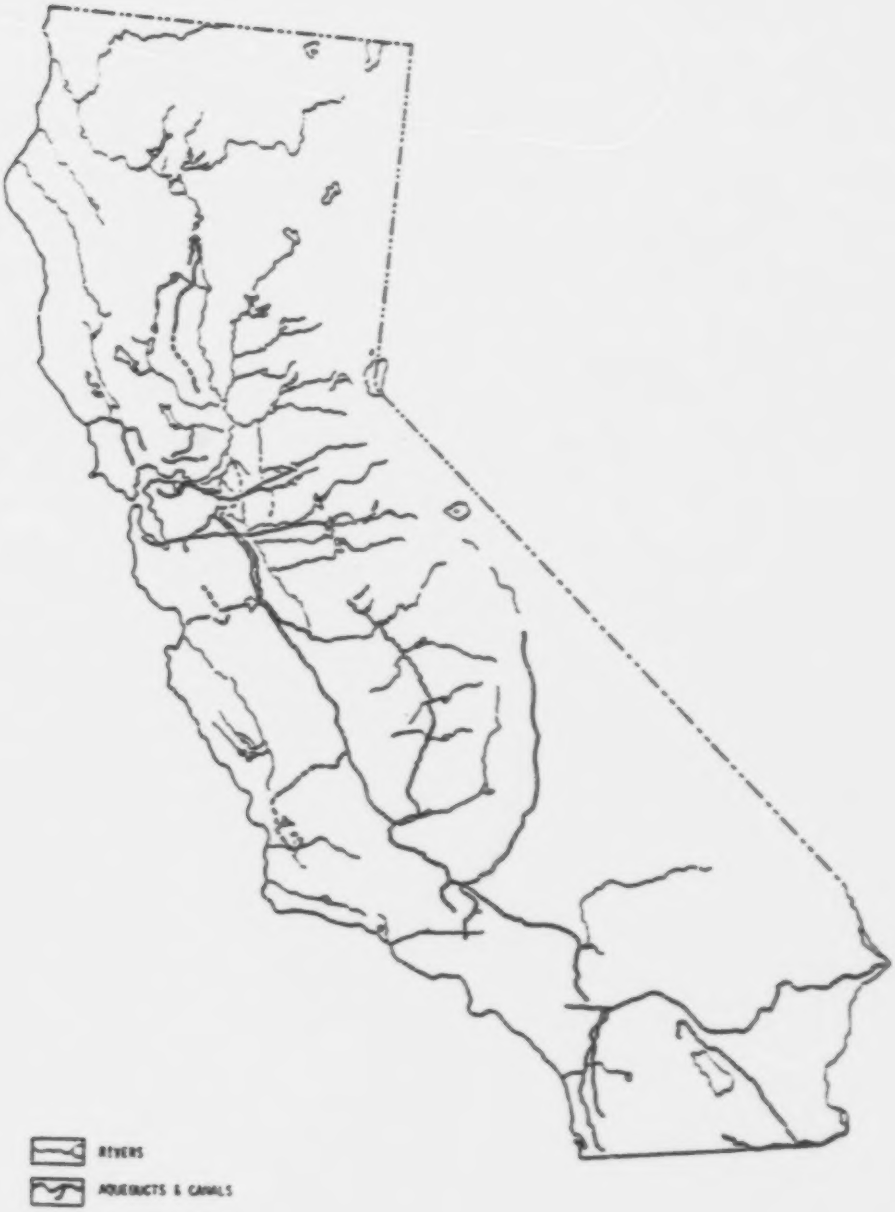
RIVERS
AQUEDUCTS & CANALS

Figure J-42. Major surface water supply and conveyance facilities in California. (State of California Resources Agency, The California Water Plan, Nov. 1974, Bull. #160-74, p. 92-93.)

## Ground Water[13]

The full extent of California's groundwater resources is not completely known. While the areas of water-bearing underground strata have been generally delineated on a statewide basis, detailed knowledge of storage capacity and other characteristics has been limited primarily to the basins most heavily used where the need is the most immediate and where a wealth of factual data is available for study. Many investigations conducted before the 1950's were limited to depths below the surface considered to represent a limit to economic pumping, even though usable water may extend to much greater depths. In some cases, actual pumping depths are in excess of original projections. At present, estimates of storage capacity are generally on the conservative side, especially in the less developed groundwater areas.

Statewide, groundwater supplies presently provide about 5.2 million acre-feet of safe yield or about 17 percent of the present dependable water supplies. Pumping in excess of safe yield is causing an estimated 2.2 million acre-feet average annual withdrawal of groundwater storage (net overdraft) throughout the state. An additional 7.6 million acre-feet of annual groundwater extraction constitutes reuse of water percolated from canals and distribution systems and from excess surface applications. In total, groundwater pumping provides about 40 percent (15 million acre-feet per year) of the present applied water needs of the state.

Groundwater basins are shown in Figure J-43. Most of the aquifers in Southern California are alluvium and older sediments. Only the coastal regions of Ventura and Los Angeles record any volcanic deposits. Groundwater conditions in the five oil-producing hydrologic areas are discussed below.

*Central Coastal Hydrologic Area*. Significant sources of ground water have been identified in 24 basins with a total area of about 3,500 square miles. Water-bearing deposits range from 200 to 4,000 feet in thickness. The gross storage capacity in the Central Coastal area is 20,000,000 acre-feet, of which 7,600,000 acre-feet are usable. Ground water is the main source of supply in the Central Coastal area. and present use

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[13] State of California, The Resources Agency, *California Water Plan, Outlook in 1974*.

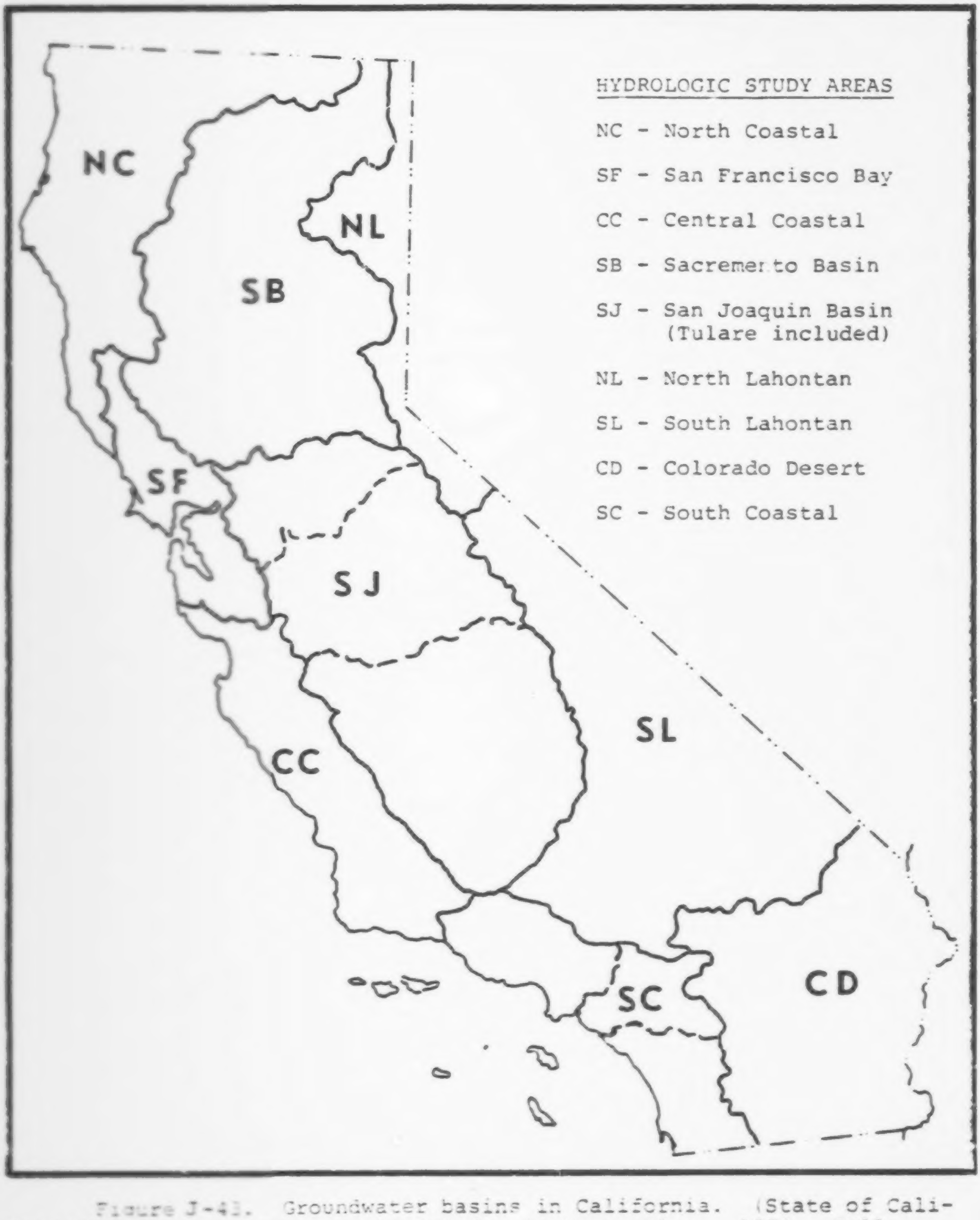
HYDROLOGIC STUDY AREAS
NC - North Coastal
SF - San Francisco Bay
CC - Central Coastal
SB - Sacremento Basin
SJ - San Joaquin Basin (Tulare included)
NL - North Lahontan
SL - South Lahontan
CD - Colorado Desert
SC - South Coastal
NC
NL
SB
SF
SJ
SL
CC
CD
SC

Figure J-41. Groundwater basins in California. (State of California Resources Agency, The California Water Plan, 1974, Bull. #160-74.

exceeds the average supply by about 140,000 acre-feet per year.

South Coastal Hydrologic Area. Significant groundwater sources have been identified in 44 basins with a total area of about 3,000 square miles. Included are four large basins (the Los Angeles coastal plain, the San Gabriel Valley, the Orange County coastal plain and the upper Santa Ana River Basin) and three major smaller basins (the Oxnard Plain, Fillmore, and San Jacinto Basins). Water-bearing deposits range from 50 to 2,500 feet in thickness. The storage capacity of the basins is about 100,000,000 acre-feet of which 7,000,000 is estimated to be usable. There is a current annual overdraft of 160,000 acre-feet, mainly in Ventura County, the Upper Santa Ana River Basin, and Coastal Orange County.

Tulare Basin Hydrologic Area. Ground water is a major source of water supply in the Tulare Basin. About 65 percent of the agricultural applied water demand and virtually all of the municipal and industrial applied water demands are met by groundwater pumping. In 1957, total storage capacity was estimated at 275 million acre-feet; as of spring 1957, 182 million acre-feet of water was in storage. Groundwater withdrawal in excess of replenishment since spring of 1957 has reduced the amount of ground water in storage by about 20,000,000 acre-feet. The 1972 overdraft of ground water in storage is estimated at 1,300,000 acre-feet annually.

South Lahontan Hydrologic Area. The water-bearing deposits range in thickness from 30 to about 2,000 feet. The total storage capacity of the area's basins is presently estimated at about 194,000,000 acre-feet of which about 700,000 acre-feet are known to be usable in Indian Wells Valley, the only basin where a determination has been made. Most of the groundwater use is in the Antelope Valley and the Mojave River Basins, both of which are in an overdraft condition totaling about 120,000 acre-feet per year.

Colorado Desert Hydrologic Area. Thickness of water-bearing deposits ranges from 50 to 2,800 feet. Total storage capacity of the hydrologic area is about 158,000,000 acre-feet; and usable capacity, determined only for the Coachella Valley, is 3,600,000 acre-feet.

Ground water is used mainly for agriculture in the Coachella Valley where a current overdraft is estimated to be about 33,000 acre-feet annually. There is also an overdraft of about 5,000 acre-feet per year in Lucerne Valley.

## Wildlife and Recreation[14]

The four biomes mentioned under land resources support a wide variety of wildlife. Some species of wildlife in California require habitat protection to survive while others need additional protected habitat to maintain populations that will be beneficial to society. Riparian habitats adjacent to rivers, lakes, and other waterways are particularly important to many species. Mountain valley habitats are limited for many deer and the few remaining elk herds; competitive uses of these valleys for cattle grazing, intensive recreation use, and reservoir sites places additional strain on the animal populations.

The Pacific Flyway for waterfowl passes through the entire length of California from the Mexican to the Oregon borders. Marsh areas which provide resting, nesting, and feeding areas are essential to maintain the present populations of these birds. Freshwater and anadromous fisheries are important to the recreational and economic welfare of the state. Good spawning areas for anadromous fish are limited and in many natural streams dry season flows are not sufficient to maintain optimum fish populations.

In the California prairie grassland, the California ground squirrel is the most characteristic species. Many animal species are grazers or burrowers, and a large number of birds are ground nesters. Insect life is abundant and heavily utilized as food by many secondary consumers. In the Mojave Desert are pocket mice, desert iguanas, and desert tortoises. Death Valley has 39 desert mammals and approximately 100 species of birds. There are fewer reptiles in the cold desert; generally, many of the same animals as are found in the hot desert are found there. Major influents are Great Basin coyote, badger, antelope and mule deer. Threatened or endangered species of fish in the California desert biomes include piute cutthroat trout; desert, tecopa, and Owens pupfish; and the Mojave chub.

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[14] State of California, The Resources Agency, California Water Plan, Outlook in 1974.

In the California chapparal, mule deer of several subspecies are wide-ranging; turkey, wild boar, and several exotic game species can be found. Typical mammals include the mountain lion, bobcat, coyote, gray fox, wood rat, skunk, and brush rabbit. Merriam chipmunk, California mouse, and five-toed kanagaroo rats are also found in this area. There are numerous small birds and lizards; but except for the tree frog, amphibians are absent.

In the coniferous forest biome are found wolverine, lynx, red squirrel, and snowshoe rabbit. Moose and white-tailed deer are widely distributed. Smaller typical species include the porcupine, woodchuck, weasels, snowshoe rabbit, northern flying squirrel, marten, red squirrel, chipmunk, and various mice and shrews.

There are 2,544 state, municipal, and county park and recreation areas in California. Altogether they comprise 892,600 acres of the state land. In 1973, fishing and hunting licenses generated over $18.7 million in income.[15] Freshwater fishing and waterfowl hunting alone accounted for over 22.1 million user days in 1970.[16]

## Energy

In 1974, total electrical energy use in California was 148 million megawatt-hours. Industrial, commercial, and residential usage were roughly equivalent, accounting respectively for 28.6 percent, 31.2 percent, and 27.6 percent of the total figure for the state.[17] Energy usage is unevenly distributed over the state, the South Coast air basin consuming about 50 percent of the state's total energy.[18]

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[15] Bureau of Census, Statistical Abstracts of the United States, 1975.

[16] State of California, The Resources Agency, California Water Plan, Outlook in 1974.

[17] Federal Power Commission, Statistics of Privately-Owned Electric Utilities in the U.S., 1974, p. 702; Federal Power Commission, Statistics of Publicly-Owned Electric Utilities in the U.S., 1974, p. 4-A to 7-A.

[18] E.J. List, Energy Use in California: Implications for the Environment (Pasadena, Calif.: California Institute of Technology, Environmental Quality Laboratory, December 1971.

In 1974, 71.4 percent of the energy consumed in California was from oil or gas hydrocarbon sources. Hydroelectric power (25.6 percent) is a significant source of energy, especially in the Northwest, Sacramento Valley, and San Joaquin Valley. Nine nuclear power plants are planned for California by the year 2000; three plants were operative, the Humboldt Bay, San Onofre Unit 1, and the Rancho Seco Unit 1, accounting for 3 percent of 1974 generation.[19] The two Diablo County Units' estimated dates of commercial operation are 1976 and 1977.[20]

## 4.4 Environmental Quality

### Air Quality

There are nine air quality maintenance areas in California; six are located in oil-producing areas of the state. The South Coast and San Diego Air Basin AQMA's include parts of Santa Barbara, Los Angeles, Riverside and San Diego Counties, and all of Orange and Ventura Counties. All of Fresno and Tulare Counties are AQMA's, as are parts of Kern and San Bernardino Counties (see Figure J-44).

The dominant pollutants of concern in nearly all of these AQMA's are suspended particulate matter and photochemical oxidants. In addition, carbon monoxide levels must be controlled in Kern County, the Sacramento Valley, the San Diego air basin, and the South Coast air basin. The South Coast basin is also designated a maintenance area for sulfur dioxide and nitrogen dioxide control. Table J-23 contains the history of monitor violations (of the NAAQS) for the AQCR's located in the southern half of California for 1974. Inspection of this table not only indicates which AQCR's were in violation, but also the number of monitors that reported these violations. Similar, though incomplete data for 1975 have been used to estimate the AQCR compliance status for 1975, and these figures are presented in Table J-24. It is noted that metropolitan Los Angeles might violate the sulfur dioxide standards due to fuel switching even though no violations had been incurred

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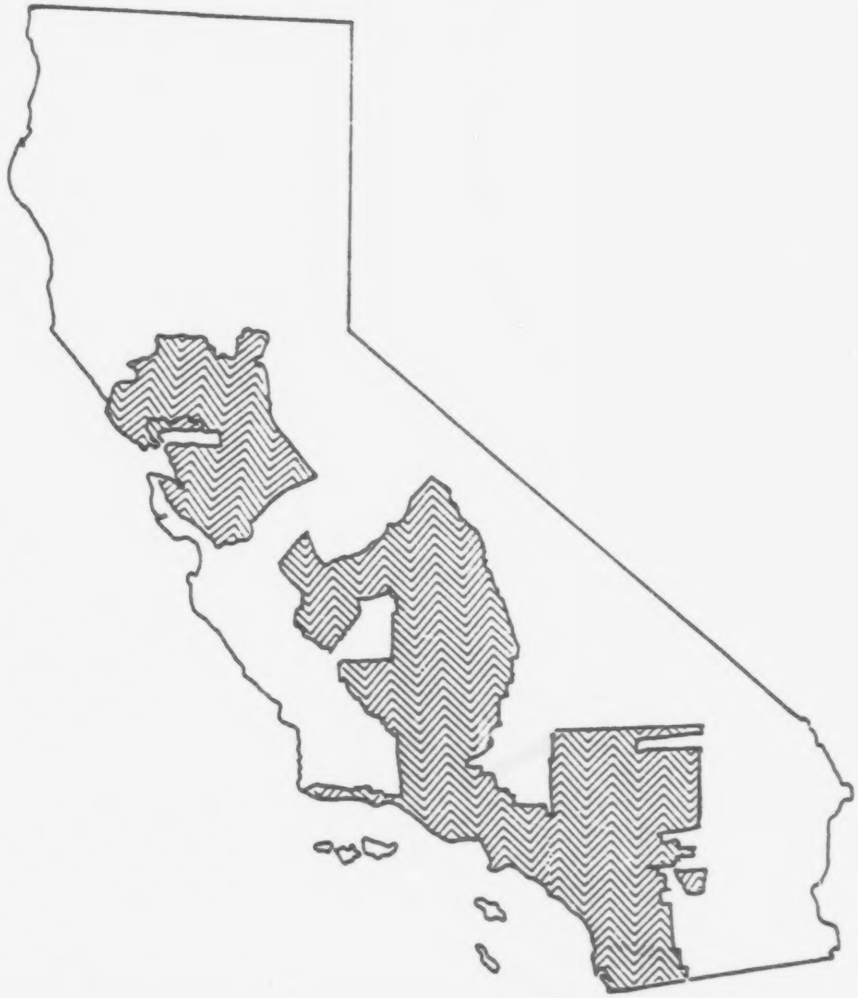
[19] Federal Power Commission, Statistics of Privately-Owned Electric Utilities; Federal Power Commission, Statistics of Publicly-Owned Electric Utilities.

[20] Western Interstate Nuclear Board, Impacts of Alternative Electricity Supply Systems for California, May 7, 1976.



| AQMA | AQMA Number | POLLUTANTS | | | | |
|---|---|---|---|---|---|---|
| | | PM | $SO_2$ | CO | $O_X$ | $NO_2$ |
| California | | | | | | |
| Fresno County | 031A | X | | | X | |
| Kern County | 031B | X | | X | X | |
| Sacramento Valley Area | 028A | | | X | X | |
| San Diego Air Basin | 019A | X | | X | X | |
| San Francisco Bay Area Air Basin | 030A | X | X | | X | |
| San Joaquin & Stanislaus Counties | 031C | X | | | X | |
| South Coast Air Basin | 024A | X | X | X | X | X |
| Southeast Desert | 033A | | | | X | |
| Tulare County | 031D | X | | | | |

Figure J-44. California Air Quality Maintenance Areas. (U.S. Environmental Protection Agency, *Guidelines for Air Quality Maintenance Planning and Analysis, Volume 14: Designated Air Quality Maintenance Areas*, December 1975, Figure 6, p. 48.)

# TABLE J-23

## NUMBER OF STATIONS REPORTING AND NUMBER OF STATIONS AT WHICH STANDARDS WERE EXCEEDED, BY AQCR, 1970-1974
## (SOUTHERN CALIFORNIA)

| | | SUSPENDED PARTICULATES | | | | | | SULFUR DIOXIDE | | | | | CARBON MONOXIDE | | | OXIDANTS | | NITROGEN DIOXIDE | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | ANNUAL | | | 24-HOUR | | | ANNUAL | | 24-HR | | 3-HR | | 1-HR | 8-HR | | 1-HR | | |
| AIR QUALITY CONTROL REGION | YR | # STA | #> SEC | #> PRI | # STA | #> SEC | #> PRI | # STA | #> STD | # STA | #> STD | #> STD | # STA | #> STD | #> STD | # STA | #> STD | # STA | #>AN STD |
| UG/CU.M | | (1) | 60 | 75 | (2) | 150 | 260 | (1) | 80 | (2) | 365 | 1300 | (2) | 40* | 10* | (2) | 160 | (1) | 100 |
| P.P.M. | | | - | - | | - | - | | .03 | | .14 | .50 | | 35 | 9 | | .08 | | |
| 024 METROPOLITAN LOS ANGELES (CALIF) | | ( 28) | | | | | | ( 3 * 1) | | | | | ( 11) | | | ( 11) | | ( 10) | |
| | 70 | 12 | 12 | 12 | 14 | 12 | 5 | 15 | 0 | 21 | 0 | 0 | 13 | 5 | 12 | 17 | 15 | 10 | 8 |
| | 71 | 12 | 11 | 10 | 14 | 15 | 4 | 13 | 0 | 21 | 0 | 0 | 15 | 2 | 14 | 16 | 16 | 13 | 8 |
| | 72 | 20 | 17 | 15 | 23 | 17 | 7 | 17 | 0 | 21 | 0 | 1 | 14 | 2 | 16 | 19 | 19 | 16 | 7 |
| | 73 | 16 | 14 | 13 | 27 | 21 | 7 | 11 | 0 | 20 | 0 | 0 | 26 | 3 | 21 | 27 | 25 | 13 | 7 |
| | 74 | 24 | 24 | 18 | 31 | 25 | 3 | 24 | 0 | 24 | 0 | 0 | 28 | 2 | 23 | 37 | 37 | 24 | 14 |
| 025 NORTH CENTRAL COAST (CALIF) | | ( 3) | | | | | | ( 1 * 0) | | | | | ( 0) | | | ( 2) | | ( 0) | |
| | 70 | 4 | 2 | 0 | 4 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 3 | 2 | 2 | 0 |
| | 71 | 4 | 2 | 0 | 4 | 2 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 3 | 3 | 2 | 0 |
| | 72 | 4 | 0 | 0 | 4 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 0 | 0 | 4 | 4 | 3 | 0 |
| | 73 | 4 | 1 | 1 | 4 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 2 | 0 | 0 | 4 | 4 | 3 | 0 |
| | 74 | 4 | 2 | 1 | 5 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 2 | 0 | 0 | 4 | 4 | 3 | 0 |
| 029 SAN DIEGO (CALIF) | | ( 3) | | | | | | ( 1 * 0) | | | | | ( 3) | | | ( 3) | | ( 0) | |
| | 70 | 3 | 3 | 2 | 3 | 3 | 0 | 1 | 0 | 1 | 0 | 0 | 0 | 0 | 0 | 1 | 1 | 1 | 0 |
| | 71 | 0 | ? | ? | 3 | 1 | 0 | 0 | 0 | 1 | 0 | 0 | 0 | 0 | 0 | 1 | 1 | 1 | 0 |
| | 72 | 1 | 0 | 0 | 1 | 0 | 0 | 1 | 0 | 2 | 0 | 0 | 1 | 0 | 0 | 6 | 6 | 1 | 0 |
| | 73 | 3 | 3 | 3 | 4 | 3 | 0 | 0 | 0 | 4 | 0 | 0 | 3 | 0 | 2 | 6 | 6 | 1 | 0 |
| | 74 | 1 | 1 | 4 | 7 | 2 | 0 | 1 | 0 | 4 | 0 | 0 | 6 | 0 | 2 | 6 | 6 | 1 | 0 |
| 031 SAN JOAQUIN VALLEY (CALIF) | | ( 12) | | | | | | ( 1 * 0) | | | | | ( 3) | | | ( 3) | | ( 0) | |
| | 70 | 2 | 2 | 1 | 4 | 4 | 1 | 0 | 0 | 1 | 0 | 0 | 4 | 0 | 1 | 4 | 4 | 7 | 0 |
| | 71 | 3 | 3 | 2 | 5 | 4 | 2 | 0 | 0 | 1 | 0 | 0 | 3 | 0 | 2 | 4 | 3 | 7 | 0 |
| | 72 | 7 | 7 | 6 | 7 | 7 | 0 | 0 | 0 | 1 | 0 | 0 | 7 | 0 | 3 | 8 | 8 | 5 | 0 |
| | 73 | 7 | 7 | 7 | 4 | 4 | 0 | 0 | 0 | 2 | 0 | 0 | 7 | 0 | 3 | 7 | 7 | 5 | 0 |
| | 74 | 10 | 10 | 7 | 16 | 13 | 3 | 1 | 0 | 2 | 0 | 0 | 7 | 0 | 3 | 6 | 6 | 5 | 0 |
| 032 SOUTH CENTRAL COAST (CALIF) | | ( 1) | | | | | | ( 1 * 0) | | | | | ( 0) | | | ( 0) | | ( 0) | |
| | 70 | 0 | ? | 0 | 2 | 0 | 0 | 0 | 0 | 0 | 0 | ? | 0 | 0 | 0 | 1 | 1 | 0 | 0 |
| | 71 | 1 | 0 | 0 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 1 | 0 | 0 |
| | 72 | 1 | 0 | 0 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 0 | 0 | 2 | 2 | 1 | 0 |
| | 73 | 1 | 0 | 0 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 0 | 1 | 2 | 2 | 1 | 0 |
| | 74 | 1 | 0 | 0 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 0 | 0 | 2 | 2 | 1 | 0 |
| 033 SOUTHEAST DESERT (CALIF) | | ( 6) | | | | | | ( 1 * 0) | | | | | ( 0) | | | ( 1) | | ( 0) | |
| | 70 | 2 | 2 | 1 | 2 | 2 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 1 | 0 | 0 |
| | 71 | 1 | 1 | 1 | 3 | 2 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 2 | 1 | 0 | 0 |
| | 72 | 1 | 1 | 1 | 1 | 1 | 1 | 0 | 0 | 1 | 0 | 0 | 3 | 0 | 1 | 6 | 4 | 3 | 0 |
| | 73 | 0 | ? | ? | 1 | 1 | 1 | 0 | 0 | 0 | 0 | 0 | 6 | 0 | 2 | 4 | 4 | 3 | 0 |
| | 74 | 0 | ? | ? | 3 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 5 | 0 | 0 | 5 | 5 | 5 | 0 |

(1) NUMBER OF STATIONS REPORTING A FULL YEAR'S VALID DATA
(2) NUMBER OF STATIONS REPORTING AT LEAST 3 24-HR VALUES OR 400 HOURLY VALUES
? STATIONS WITH INCOMPLETE DATA MAY BE EXCEEDING THE ANNUAL STANDARD; SEE APPENDICES
* CO STANDARDS ARE IN MILLIGRAMS PER CUBIC METER

## TABLE J-24

## ESTIMATED ATTAINMENT OF NATIONAL TSP AND $SO_2$ AMBIENT AIR QUALITY STANDARDS BY AIR QUALITY CONTROL REGION[1]

(SOUTHERN CALIFORNIA)

| AQCR | Probably will attain | Probably will not attain | Attainment status uncertain |
|---|---|---|---|
| 024. Metropolitan Los Angeles | | TSP | $SO_2$ - Fuel switching may cause violations |
| 025. North Central Coast | TSP<br>$SO_2$ | | |
| 029. San Diego | | TSP<br>Non-point sources | $SO_2$<br>Fuel switching may cause violations |
| 031. San Joaquin Valley | $SO_2$ | TSP<br>Fugitive dust area | |
| 032. South Central Coast | TSP<br>$SO_2$ | | |
| 033. Southeast Desert | $SO_2$ | TSP<br>Fugitive dust area | |

---

[1] Attainment is based on most recent air quality data available; these do not, in all cases, reflect final compliance. Estimated attainment status for both TSP (total suspended particulate) and $SO_2$ (sulfur dioxide) is based on annual and/or 24-hour averages. Comments noting factors that prevent attainment are occasionally included in the last two columns; these comments, like the attainment status, are best estimates and/or judgements.

the previous two years. The same is true for the San Diego AQCR. Otherwise it is not surprising that suspended particulates should be the major problem in 1975 as it had been in the past. The State of California has been asked to revise its clean air implementation plans to effect better control over particulates, carbon monoxide, and nitrogen dioxide releases.

## Water[21]

### Surface Water Quality

Thirty-one water quality class segments have been designated in California. These are significant areas in view of the attention that must be directed to them to conform to PL 92-500. Basins of particular interest in consideration of oil-producing technologies include the following.

Central Coastal Basin. Water quality problems in the Central Coastal Basin are varied. Short outfalls into shallow and poorly circulating ocean waters are causing problems along the north and south shores of Monterey Bay and at Santa Barbara. Agricultural drainage, nutrients and pesticides are problem sources in the Salinas River; septic tank system problems exist in the San Lorenzo subbasin and at smaller communities along the coast such as Cambria.

Tulare Lake Basin. The major water problem in the Tulare Lake Basin is a demand for more water than can be supplied by existing sources. This has caused severe groundwater overdrafting and an adverse salt balance in this essentially closed basin.

South Lahontan Basin. Water quality problems in the northern part of the South Lahontan Basin relate to improper treatment of municipal and domestic wastewaters.

West Colorado River Basin. The major water quality problem in the West Colorado River basin is the high and increasing salinity of the Salton Sea. The sea is somewhat saltier than the oceans and is approaching the salinity in which fish can no longer survive. Other problems are: (1) the limited amount and increasing salinity of the Colorado River supply; (2) nutrient contamination of the Salton Sea by inflows of the New, Alamo and Whitewater Rivers from agricultural, municipal and industrial wastewaters; and (3) overdraft of high quality ground water in the Coachella Valley.

---

[21] State of California, The Resources Agency, California Water Plan, Outlook in 1974.

## Groundwater Quality

The chief source of California's groundwater quality problems is overdrafting. Water demands in the central and southern coastal regions exceeding local dependable supplies have resulted in overdrafting-provoked salinity intrusion in certain coastal aquifers. These and other groundwater areas of interest are discussed below.

Central Coastal Basin. Salt balance and groundwater quality problems exist in the Lower Salinas Valley, Hollister-Tres Pinos, Soda Lake and Carmel River areas due to extractions and return flows. Groundwater quality is not suitable in portions of the Santa Maria and Santa Ynez subbasins. In the southern region of the basin there is a current overdraft of about 50,000 acre-feet per year, mainly in Santa Barbara County, but including inland areas of San Luis Obispo County.

South Coastal Basin. The dissolved solids content of the water is generally less than 1,000 mg/l, but locally is more than 36,000 mg/l. Chronic overdrafting has led to land susidence in some areas of the basin.

South Lahontan Basin. Most valleys have some ground water with less than 800 mg/l, dissolved solids but many also have waters with several thousand mg/l. Poor quality ground waters, caused locally by percolation of wastewaters from mining operations and more generally by down-gradient subsurface flow, are prevalent in the Amargosa River area. Similar groundwater degradation occurs near Boron due to percolation of mine waters. Occurrences of overflow of the Lancaster oxidation ponds offer a potential public health hazard. At Barstow inadequately treated municipal and industrial wastewaters have created a "tail" of poor quality ground water downstream of the discharge point causing significant quality deterioration in local domestic well supplies.

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Tulare Lake Basin. The major water problem in the Tulare Lake Basin is a demand for more water than can be supplied by existing sources. This has caused severe groundwater overdrafting and an adverse salt balance in this essentially closed basin. A problem associated with overdraft is deep subsidence. Subsidence on the order of 25 feet has been experienced in portions of the basin since 1935.

Colorado Desert Hydrologic Area. Most valleys have some ground water with less than 600 mg/l dissolved solids, but some have as much as several thousand mg/l. The quality of the large volume of ground water in the Imperial Valley is so poor that its use is very limited.

## Land

Subsidence of the land surface has been occuring in California for many years as a result of man's activities. Subsidence can be categorized into four types on the basis of causative mechanisms: groundwater withdrawal subsidence, oil or gas withdrawal subsidence, hydrocompaction subsidence, and peat oxidation subsidence. The distribution of the four types of subsidence in California is shown in Figure J-45.

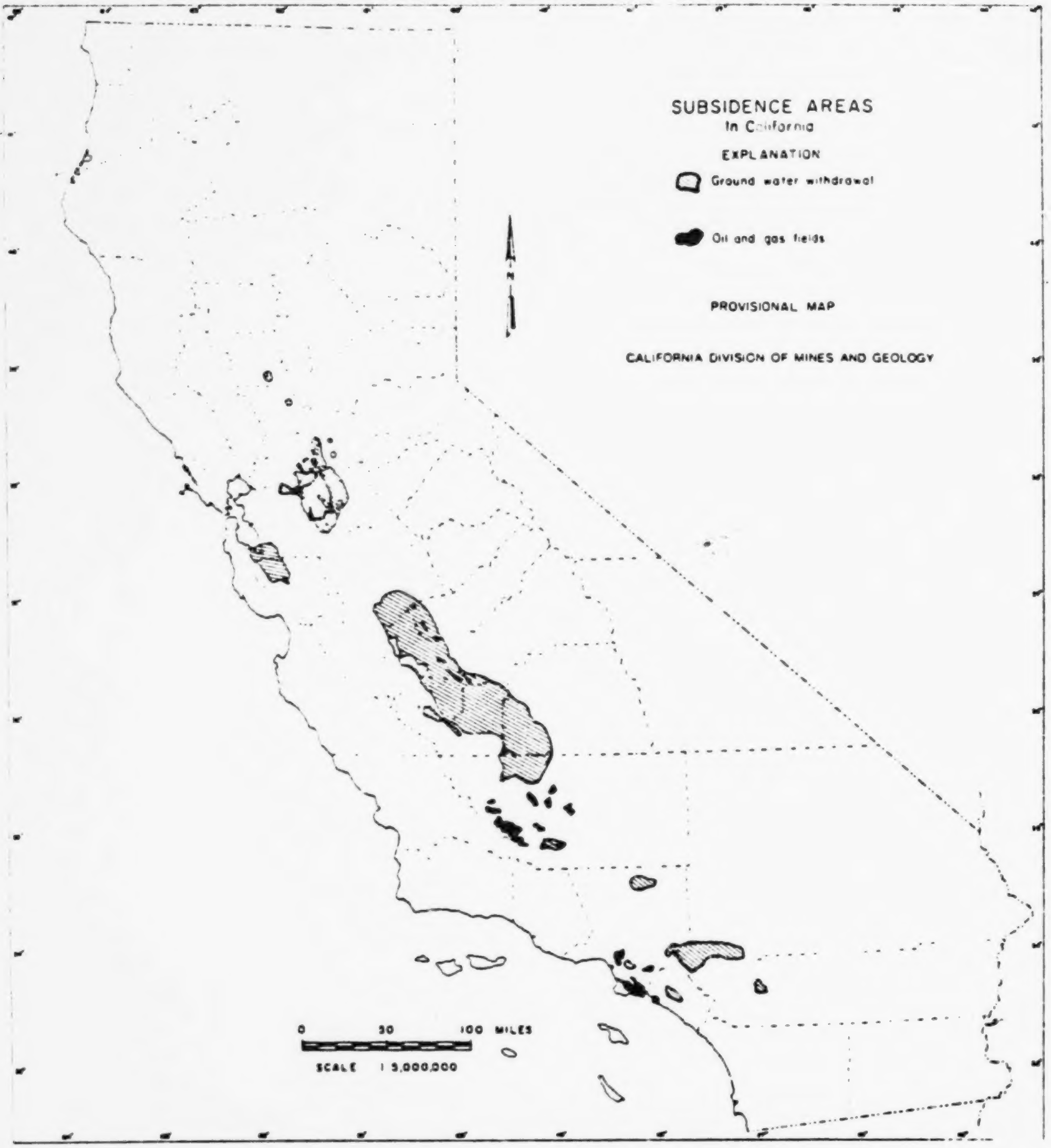
SUBSIDENCE AREAS
In California
EXPLANATION
Ground water withdrawal
Oil and gas fields
PROVISIONAL MAP
CALIFORNIA DIVISION OF MINES AND GEOLOGY
N
0
50
100 MILES
SCALE 1:5,000,000

Figure J-45. Subsidence areas in California. (U.S. Department of the Interior, 1975 Outer Continental Shelf Lease Sale Offshore Southern California, Vol. I, Figure II-6b, p. 87, from California Division of Mines and Geology, 1973.)

# 5. Louisiana

## 5.1 Physiography and Climate

### Physiography

The whole state of Louisiana is contained within the Gulf Coastal Plain. Topographical variation is slight, consisting mainly of a series of low ridges and valleys paralleling the coast. The state can be divided into three regions -- hills, terraces, and lowlands. Lowland regions made up of floodplain and marsh are found along the Gulf coast and the Mississippi floodplain. The hills of Louisiana are located in the northwestern parishes of the state, and the terraces or flat uplands are found to the east and west of the Mississippi flood plain.

Figure J-46 indicates the five major natural regions of Louisiana. The coastal marsh has both fresh- and saltwater regions with largely muck and peat soils. The Mississippi floodplain is characterized by passes (the delta), natural levees (frontlands of riverbanks standing above the swamp level), and swamps. The Red River Valley is distinctive by virtue of its red soils. Terraces represent older alluvium and are broken down into three types on the basis of relief, soil, and vegetation: hill regions exhibit the most mature soil types and two major forest types, longleaf and shortleaf pine.[1]

### Climate

In Louisiana, maximum precipitation occurs in the southeast near the coast and decreases in a northwesterly direction, as illustrated in Figure J-47. Mean annual values range from 48 inches in the northwest to 64 inches in the southeast. Humidity is highest in south Louisiana, and declines to the north and west away from the coast.

Generally, movement of air in Louisiana is from west to east. Louisiana has essentially a two-season climate, distinguished by either the absence or presence of polar fronts. Winter is a time of alternating air-mass control, tropical then polar, with all of the frontal effects and an

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[1] Fred B. Kniffen, Louisiana: Its Land and People (Baton Rouge: Louisiana State University Press, 1968).

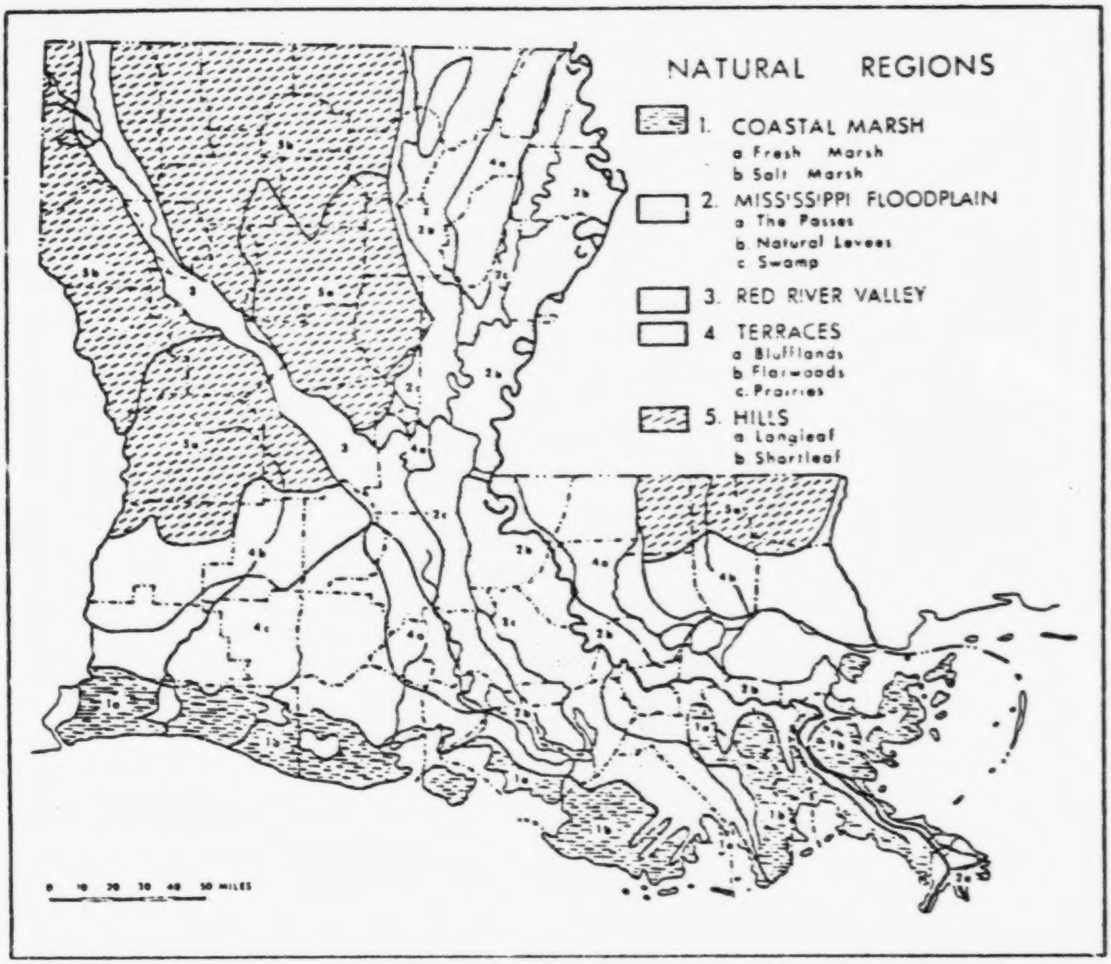
NATURAL REGIONS
1. COASTAL MARSH
a Fresh Marsh
b Salt Marsh
2. MISSISSIPPI FLOODPLAIN
a The Passes
b. Natural Levees
c Swamp
3. RED RIVER VALLEY
4 TERRACES
a Blufflands
b Flatwoods
c. Prairies
5. HILLS
a Longleaf
b Shortleaf
0 10 20 30 40 50 MILES

Figure J-46. Louisiana natural regions. (Fred B. Kniffen, *Louisiana: Its Land and People* (Baton Rouge: Louisiana State University Press, 1968).)

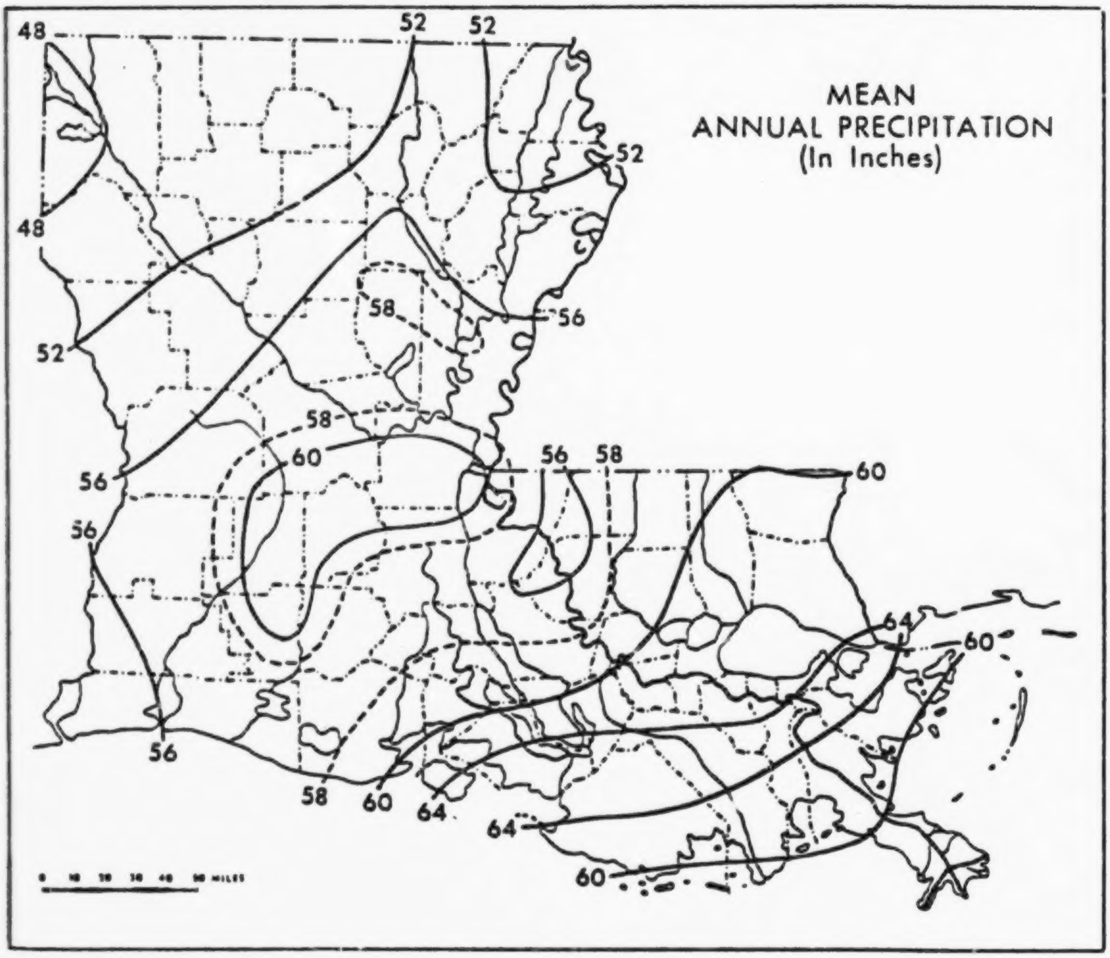
MEAN
ANNUAL PRECIPITATION
(In Inches)
48
48
52
52
52
52
56
56
56
56
56
58
58
58
58
60
60
60
60
60
64
64
64
0 10 20 30 40 50 MILES

Figure J-47. Louisiana mean annual precipitation. (Fred B. Kniffen, Louisiana: Its Land and People (Baton Rouge: Louisiana State University Press, 1968).)

outward (Gulfward) monsoon effect. During the period of June through November, tropical storms occur with a high frequency. In a period of 83 years, Louisiana experienced 92 tropical storms. Hurricanes appear on the average of once every 4 years, with South Louisiana frequently suffering the greatest impact.[2] The average wind speeds recorded across Louisiana range from less than 3.5 meters per second in New Orleans to greater than 4 meters per second in Shreveport. Low wind speeds are quite common all across the state, occurring 11 percent of the time at Lake Charles and over 23 percent of the time at Monroe. The state average of reported hours of winds less than 1.5 meters per second accounts for 17 percent of all reporting periods.

## 5.2 Population and Economy

### Population

The figures for 1970 place the Louisiana population at 3,641,000 and a density of 37.2 people per square mile. A little more than 66 percent of the population is urban. New Orleans, Shreveport, and Baton Rouge are major population centers accounting for about 26 percent of the total state population.[3] About 44 percent of the population lives in coastal Louisiana.[4]

For many years Louisiana's unemployment rate has been excessively high in comparison with those of the other southern states and of the nation as a whole. Louisiana's seasonally adjusted unemployment rates for the last three months of 1975 were 8.6, 8.6 and 8.3 percent in comparison with the national figures of 8.5, 8.3 and 8.3 percent. Per capita personal income in 1974 ($4,391) compared favorably with other southern states, but was below the national and southeastern figures.[5]

---

[2] U.S. Bureau of the Census, Statistical Abstract of the United States, 1975, 96th Edition, 1975.

[3] Louisiana State Planning Office, Office of the Governor, The State of the State in 1976: An Economic and Social Report to the Governor, May 1, 1976.

[4] Louisiana Department of Conservation, Secondary Recovery and Pressure Maintenance Operations in Louisiana, 1974.

## Economy

In 1974, personal income derived from non-farm sources was about 12 times that from agricultural sources. Wholesale and retail trade and manufacturing were the largest contributors to the total industrial figure of $9,963 million, each accounting for about 22 percent of the total.[6]

Chemicals, food, and petroleum are the leading major industry groups in value added by manufacture.[7] In 1974, chemical and allied products represented about 19.4 percent of the personal income derived from manufacturing, while manufacture of food and related products contributed approximately 12 percent. Petroleum refining income was on the order of 10 percent of the total manufacturing figure of $2,206 million dollars. Other significant manufacturing groups included transportation (excluding motor vehicles), paper and allied products, and lumber and wood products (excluding furniture). Forestry constitutes an important multi-billion dollar industry for the Louisiana economy. In 1975, the total economic impact of the forest industry was in excess of $2 billion through value added by harvest operations, transportation, manufacture, and marketing of finished products.[8]

The petroleum industry exerts a profound influence on the state's economy. More than 62,000 people are employed in the production and refining of crude petroleum and natural gas.[9] Oil fields are scattered throughout the state, with the greatest concentration of fields in the northwest and along the coast, as seen in Figure J-48. During 1974, Louisiana produced a total of 385,820,545 barrels of crude and condensate, 27.7 percent of which was from secondary recovery projects.[10] Parishes with sites amenable to secondary and tertiary recovery include Bossier, Caddo, Cameron, Iberia, Iberville, and St. Landry.

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[5] Louisiana Department of Conservation, Louisiana Geological Survey, and Louisiana Department of Public Works, Water Resources Pamphlet No. 26, Pumpage of Water in Louisiana, 1970, Baton Rouge, July 1970.

[6] Louisiana State Planning Office, The State of the State in 1976.

[7] U.S. Bureau of Census, Statistical Abstract of the United States, 1975.

[8] Louisiana State Planning Office, The State of the State in 1976.

There are approximately 42,000 farms in Louisiana that account for 9.8 million acres or 31.6 percent of the state's 31 million acres. The state ranks 28th in the nation in total farm marketings of crop and livestock. Principal commodities in order of marketing receipts are soybeans, rice, cattle, and cotton.[11]

Nearly half of the approximately 4.6 million acres of cropland presently in production are located in the bottomlands of the Red and Mississippi Rivers. These areas consist of level, highly productive soils that are well suited to the economic use of large farming equipment. Approximately 90 percent of the remaining 2.3 million acres of crops are grown on silty upland and coastal prairie soils. Value of crops in 1975 was over $10 billion.[12]

In 1974, cash receipts from livestock and products were approximately $360 million. This figure represents about 29 percent of total cash receipts from farm marketings. Cattle, calves and related products were the most significant contributors to livestock receipts in this period.[13]

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[9] Louisiana State Planning Office, The State of the State in 1976.

[10] Department of Conservation, Secondary Recovery and Pressure Maintenance Operations in Louisiana, 1974.

[11] U.S. Bureau of Census, Statistical Abstract of the United States, 1975.

[12] Louisiana State Planning Office, The State of the State in 1976.

[13] U.S. Bureau of Census, Statistical Abstract of the United States, 1975.

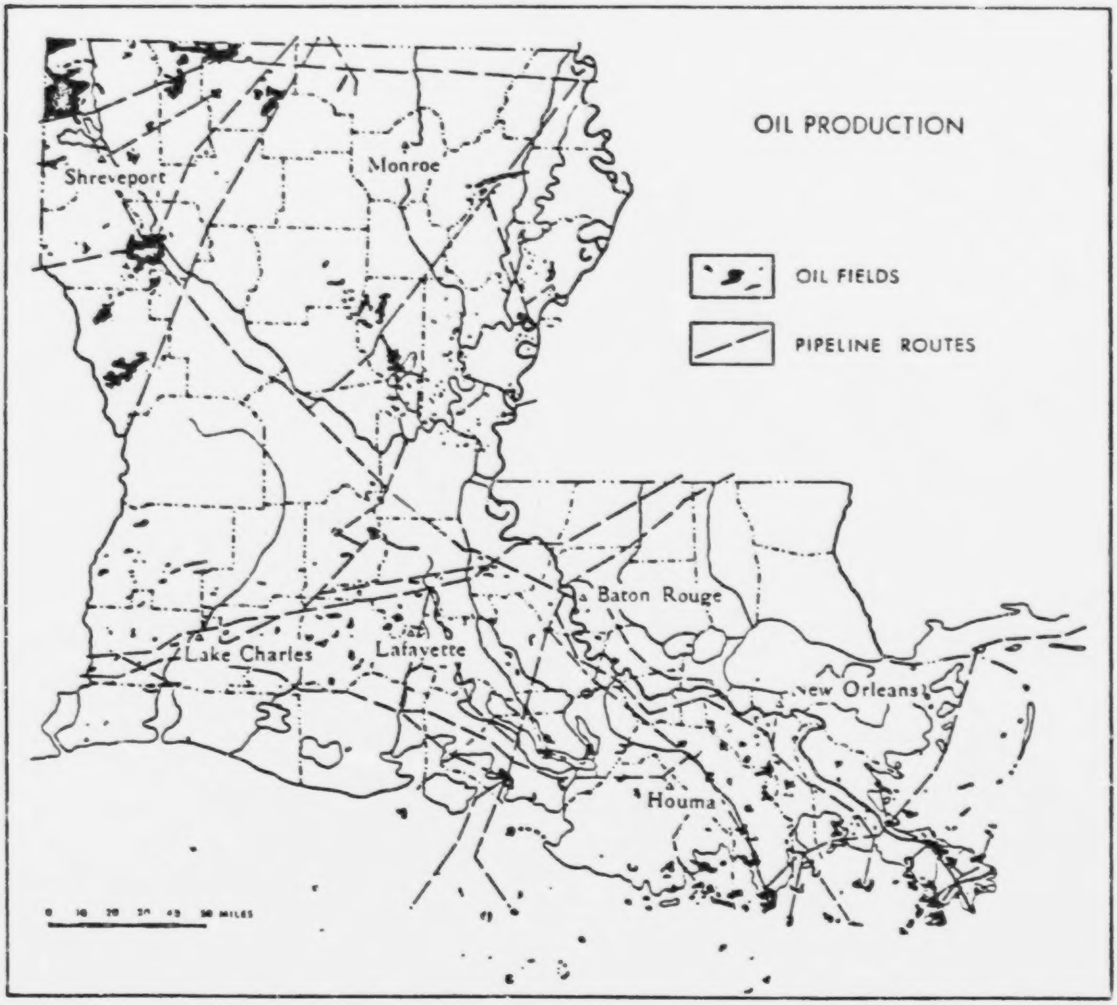
OIL PRODUCTION
OIL FIELDS
PIPELINE ROUTES
Shreveport
Monroe
Baton Rouge
Lake Charles
Lafayette
New Orleans
Houma
0 10 20 30 40 50 MILES

Figure J-48. Louisiana oil production. (Fred B. Kniffen, Louisiana: Its Land and People (Baton Rouge: Louisiana State University Press, 1968).)

## 5.3 Resources

### Land[14]

Land usage figures show that upland forests account for the greatest land use (30.6 percent) in Louisiana. Twenty-four percent of the state's total area is agricultural. The water area of 22.7 percent is apportioned between Gulf of Mexico (14.2 percent) and inland water (8.5 percent). Louisiana's wetlands cover more area than the entire state of Maryland. 6,780,644 acres of swamp and marsh cover 18.6 percent of the land. Only 3.5 percent of the state's land is used for urban and built-up purposes; almost half of that amount (or 1.7 percent) is in extractive uses, mainly oil and gas.

Louisiana has been divided into eight planning districts as seen in Figure J-49. District 1 is principally water and wetlands, with more than 69 percent of the total land area taken up with water. District 3 includes 4.2 percent of the state's wetlands and accounts for more than 41 percent of its area. Agricultural land usage is highest in District 8 at 46 percent of district land area. The major forest area of the state is located in District 7 where 70 percent of the land is occupied by forest. Urban and built-up land is greatest in District 3, and represents about 7.4 percent of the district land.

Table J-25 shows land use percentage figures for the eight state planning districts. The figures above the diagonal line represent the percentage of district land used, while the figures below the diagonal line represent the state percentage of that particular land use located within that planning district. For example, agricultural land use in District 4 is 33.2 percent, representing 5.0 percent of the total state area.

Districts 1 and 3 are predominantly water and wetlands. Districts 2, 6, and 7 are covered mostly by upland forest with agricultural land occupying second position. Districts 4 and 5 are primarily agricultural, with significant wetland areas. Eighty percent of District 8 is taken up with agricultural and forest activities.

District 3 has 36.7 percent of Louisiana's 618,735 acres of extractive land. District 4 has 19.9 percent of the state's extractive lands, while District 1 has 16.2 percent. These three districts account for 72.8 percent of all extractive lands in Louisiana.

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[14] Louisiana State Planning Office, The State of the State in 1976.

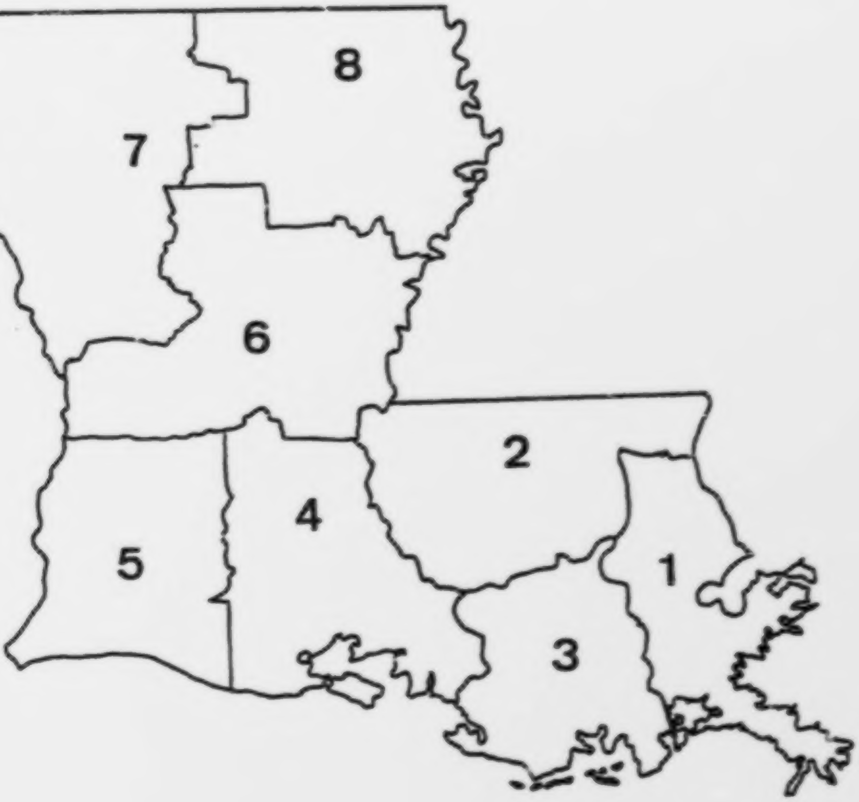

Figure J-49. Louisiana state planning districts. (Louisiana State Planning Office, The State of the State in 1976: An Economic and Social Report to the Governor, Figure 2-2, p. 33, from Louisiana State Planning Office.)

## TABLE J-25

## LOUISIANA STATE PLANNING DISTRICT LAND USES

PERCENT OF DISTRICT LAND / PERCENT OF TOTAL LAND

| LAND USE | DISTRICT 1 | DISTRICT 2 | DISTRICT 3 | DISTRICT 4 | DISTRICT 5 | DISTRICT 6 | DISTRICT 7 | DISTRICT 8 |
|---|---|---|---|---|---|---|---|---|
| Urban and Built-up Land | 4.1 / 0.6 | 3.5 / 0.3 | 7.4 / 0.8 | 3.7 / 0.6 | 2.2 / 0.2 | 2.6 / 0.3 | 3.2 / 0.5 | 2.2 / 0.2 |
| Agricultural Land | 2.1 / 0.4 | 31.8 / 3.1 | 9.5 / 1.0 | 33.2 / 5.0 | 30.2 / 3.1 | 24.5 / 3.1 | 21.2 / 3.0 | 46.0 / 53.0 |
| Forest Land | 4.8 / 0.8 | 44.9 / 4.4 | 1.0 / 0.1 | 7.7 / 1.2 | 27.3 / 2.8 | 56.8 / 7.3 | 70.0 / 9.9 | 36.4 / 4.2 |
| Water | 69.6 / 11.1 | 3.4 / 0.4 | 39.8 / 4.1 | 34.3 / 5.1 | 11.1 / 1.1 | 1.7 / 0.2 | 2.8 / 0.4 | 1.7 / 0.2 |
| Wetland | 18.2 / 2.9 | 16.4 / 1.6 | 41.3 / 4.2 | 20.5 / 3.1 | 29.0 / 3.0 | 14.3 / 1.8 | 2.5 / 0.4 | 13.5 / 1.6 |
| Barren Land | 1.0 / 0.2 | 0.1 / 0.0 | 0.8 / 0.2 | 0.4 / 0.1 | 0.2 / 0.0 | 0.1 / 0.0 | 0.2 / 0.0 | 0.3 / 0.1 |

## Surface Water[15]

Louisiana has numerous streams, lakes, and waterways, and extensive wetlands. Additionally, the mouth of one of the largest freshwater drainage systems in North America is located within the boundaries of the state. Although Louisiana's water resources are vast, they are not located in areas of greatest demand. On a local scale, some water-related problems have become intense and undoubtedly will increase in severity if unchecked.

The surface water system of Louisiana forms a fine network extending throughout the state (Figure J-50). In varying degrees, the source of all surface water is precipitation, runoff, inflows to the state, and ground water. The basic quality of surface water is dependent upon the characteristics of its source. The Mississippi, Atchafalaya, Pearl, Sabine, and Red Rivers and Toledo Bend and Maurepas Lakes are the major surface freshwater bodies in the state. In addition, there are numerous other lakes, reservoirs, channels, bayous, and swamps.

In 1970, 7,542 million gallons per day of surface water were pumped in Louisiana. This amount represents 83 percent of all water pumped in the state for industrial, thermoelectric, irrigation and livestock, and public and rural domestic use. Surface water supplies 88 percent of all water used by industry, 54 percent of all water used for public supply and rural domestic use, and about 50 percent of the total water pumped for irrigation and livestock.

Industry is the largest water user in Louisiana, accounting for nearly 46 percent of the total state pumpage of surface and ground water. Total pumpage for thermoelectric use is about 32 percent, while irrigation and livestock take up about 17.4 percent of combined surface and ground water used. Public supplies and rural domestic demands in 1970 were about 5 percent of the total ground and surface water pumpage of 9,060 mgd.

## Ground Water[16]

More than three-fourths of Louisiana is underlain by freshwater aquifers capable of yielding moderate to large

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[15] Louisiana State Planning Office, The State of the State in 1976.

[16] Department of Conservation, Pumpage of Water in Louisiana, 1970.

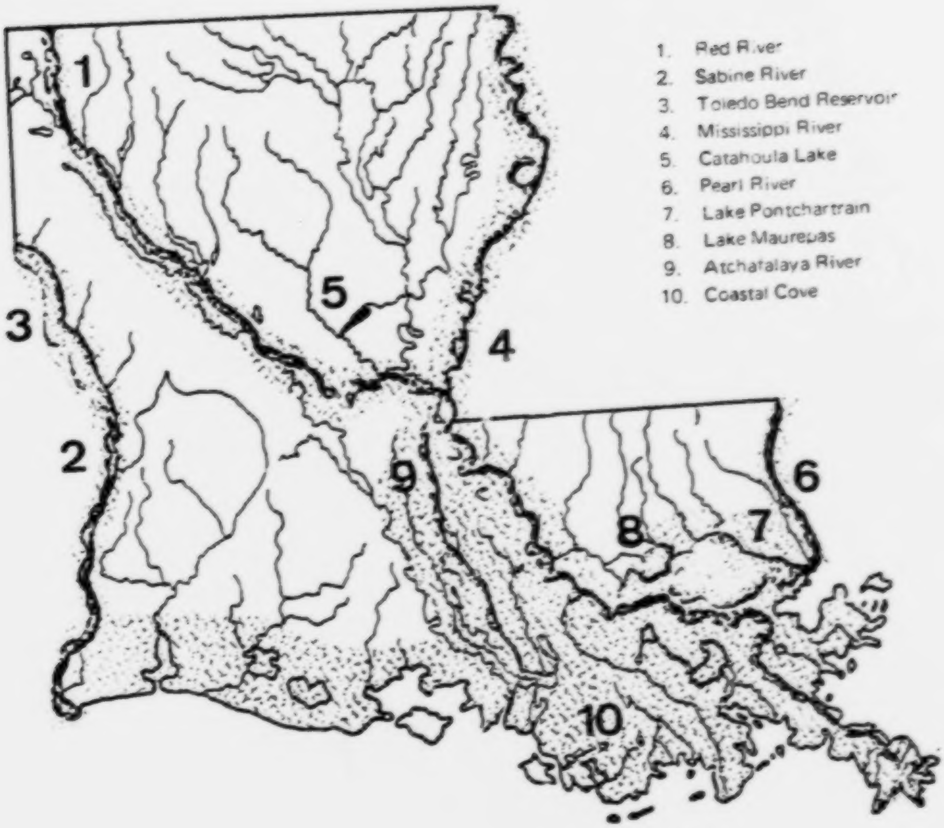
1
2
3
4
5
6
7
8
9
10
1. Red River
2. Sabine River
3. Toledo Bend Reservoir
4. Mississippi River
5. Catahoula Lake
6. Pearl River
7. Lake Pontchartrain
8. Lake Maurepas
9. Atchafalaya River
10. Coastal Cove

Figure J-50. Surface water features of Louisiana. (Louisiana State Planning Office, The State of the State in 1976, Figure 5-1, p. 58, from Louisiana State Planning Office.)

supplies of ground water, with a considerable part of it soft and low in mineral matter. About two-thirds of all ground water pumped in the state is from Quaternary deposits of Pleistocene and Recent Ages which underlie most of Louisiana. Some of the most extensive and prolific freshwater aquifers of North America are located in Louisiana. A pronounced exception is the coastal area, where virtually no fresh ground water is found. The base of freshwater in aquifers throughout the remainder of the state ranges in depth from in excess of 3,000 feet to 100 feet or less. Saline lenses or saline water aquifers occur locally at intermediate depths with freshwater aquifers above and below. For most aquifers in Louisiana, precipitation is the principal source of recharge.

For the purposes of groundwater examination, Louisiana can be divided into five geographic areas. These areas include: Southwestern Louisiana, Baton Rouge Area, Baton Rouge-New Orleans Area, Southeastern Louisiana, and Northern and Central Louisiana. A map illustrating the general availability of ground water in Louisiana is reproduced in Figure J-51. An extensive discussion of well yields is found in Water Resources Bulletin No. 1, "Ground Water in Louisiana."

The principal use of ground water in Louisiana is for irrigation and livestock; more than 50 percent of all ground water pumped is used for these purposes. Industry and public supplies and rural domestic use account respectively for 32.5 percent and 13.6 percent of ground water used. About 17 percent of the water pumped in the state comes from ground water.

### Wildlife and Recreation[17]

Wildlife resources in Louisiana are quite extensive. Forest and farm game abound. Species of forest game include white-tailed deer, wild turkey, squirrels, and American woodcock. There are cougar, black bear, southern wolf, bobcat, and fox. Farm game species include bobwhite quail, mourning dove, rabbits, waterfowl, and fur animals such as muskrat, mink, nutria, otter, and beaver.[18]

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[17] Louisiana State Planning Office, The State of the State in 1976.

[18] Lyle S. St. Amant, Louisiana Wildlife Inventory and Management Plan (Pittman-Robertson Section--Fish and Game Division, Louisiana Wildlife and Fisheries Commission, 1959).

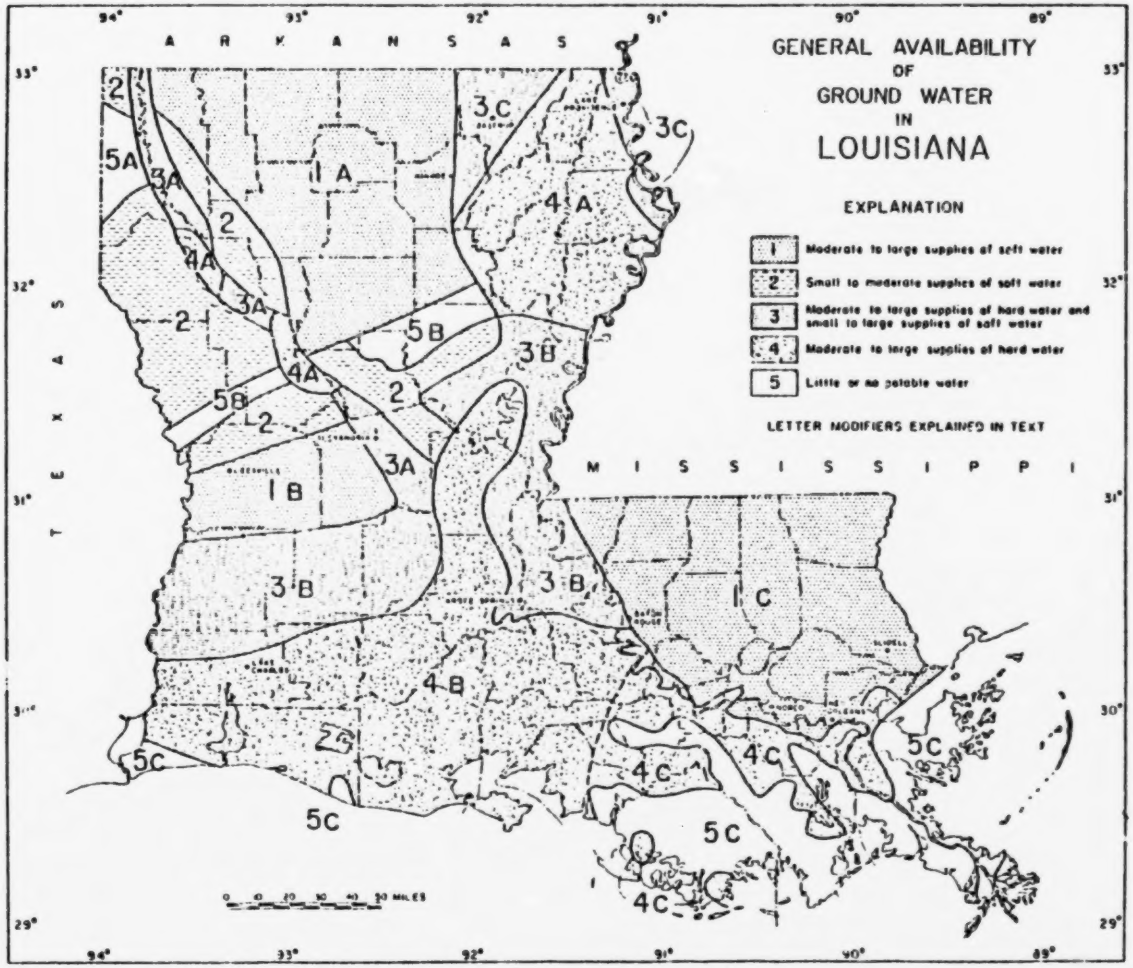
GENERAL AVAILABILITY
OF
GROUND WATER
IN
LOUISIANA
EXPLANATION
1 Moderate to large supplies of soft water
2 Small to moderate supplies of soft water
3 Moderate to large supplies of hard water and small to large supplies of soft water
4 Moderate to large supplies of hard water
5 Little or no potable water
LETTER MODIFIERS EXPLAINED IN TEXT
ARKANSAS
TEXAS
MISSISSIPPI
94°
93°
92°
91°
90°
89°
33°
32°
31°
30°
29°
1A
1B
1C
2
3A
3B
3C
4A
4B
4C
5A
5B
5C
0 10 20 30 40 50 MILES

Figure J-51. General availability of ground water in Louisiana. (Department of Conservation, Louisiana Geological Survey and Louisiana Department of Public Works, Groundwater in Louisiana Water Resources, Bulletin Number 1, August 1960, Plate 4.)

Hunting licenses in 1975 brought in a total revenue of $1.2 million. The total price of commercial fur catch (including pelts and meat) to the trapper in Louisiana was $10.8 million. The greatest number of pelts taken in Louisiana came from nutria and muskrat; money earned by trappers from these two animals was 84.5 percent of the total value of all pelts and meat.

Louisiana fishery resources are large and diverse. Commercial landings in 1974 totaled nearly 1.2 billion pounds, with a dockside value of $86 million. Additional processing and handling brought the total value to an estimated $200 million. Approximately 17,000 people are employed in commercial fishing and catch-processing. Recreational fishing is also a significant factor in Louisiana and is valued at over $200 million annually. Fishing licenses alone brought in about $200,000 in revenue in 1974.

Louisiana received approximately $950 million or 6 percent of the total expenditures by travelers in the South in 1975. More than 7 million visitors were recorded at selected tourist attractions in 1975. The state has 23 state parks offering various activities including swimming, boating, fishing, and camping.

### Energy

In 1973, Louisiana produced 54,162 million kWh of electric energy. Fossil fuel-powered utilities accounted for 76.6 percent of electrical energy produced; the remaining 23.4 percent was supplied by industrial plants. Total installed electrical generating capacity for the state in 1973 was 12,095 megawatts.[19]

## 5.4 Environmental Quality

### Air Quality

There is one Air Quality Maintenance Area in Louisiana situated in the northwest corner of the state (see Figure J-52). Bossier, Caddo, and Webster parishes fall within this area.

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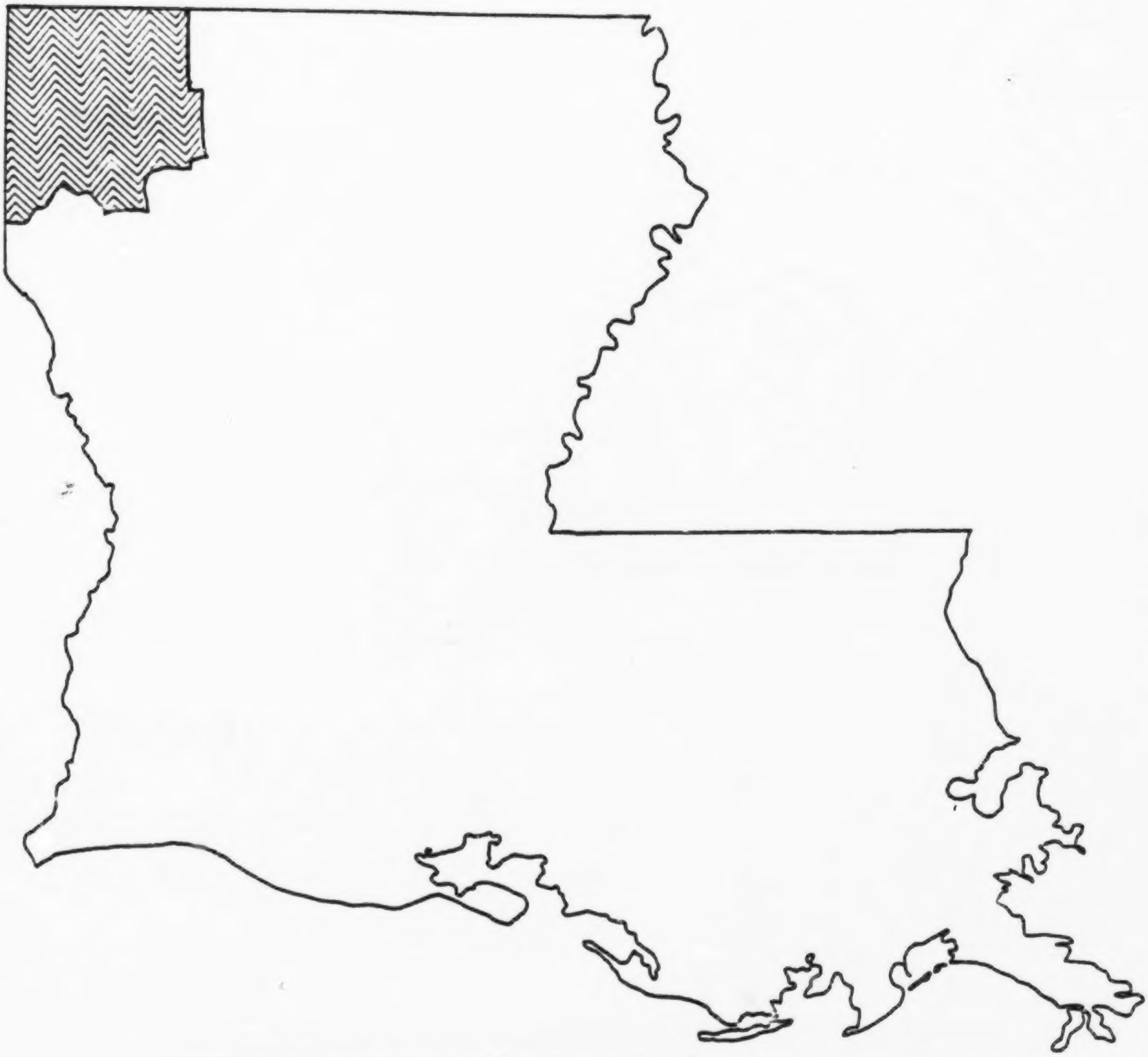
[19] U.S. Bureau of Census, *Statistical Abstract of the United States, 1975*.



| AQMA | AQMA Number | POLLUTANTS | | | | |
|---|---|---|---|---|---|---|
| | | PM | $SO_2$ | CO | $O_X$ | $NO_2$ |
| Louisiana | | | | | | |
| Shreveport | 022A | X | | | | |

Figure J-52. Louisiana Air Quality Maintenance Areas. (U.S. Environmental Protection Agency, *Guidelines for Air Quality Maintenance Planning and Analysis, Volume 14: Designated Air Quality Maintenance Areas*, December 1975, Figure 20, p. 84.)

High levels of particulate matter constitute the bulk of the pollutant problem.[20] This is particularly evident in Table J-26, which indicates those areas of Louisiana that are thought to be in violation of the national ambient air quality standards. These estimates of attainment status are based on the incomplete data reported for 1975. Louisiana has been asked to revise its clean air implementation plan to allow for a wider range of control over sources of particulates and those sources that are active contributors to the oxidant problem. Louisiana's air quality standards are compared to the national standards in Table J-13. Table J-27 contains 1974 monitor violations for all criteria pollutants.

## Surface Water Quality[21]

Generally, sufficient quantities of good quality surface water are available on a regional basis in Louisiana. However, significant water quality problems exist locally. Hardness and dissolved solids content vary greatly throughout the state, with concentrations usually increasing from north to south. Bacteriological quality is highly variable, also. The density of urban, industrial, and agricultural development has an immense impact upon regional and local water quality.

Surface water becomes polluted as a result of chlorides, oxygen deficiency, heavy metals, various organic compounds and natural and oilfield brines. Oxygen deficiency may be attributed primarily to municipal and industrial effluents. The physical quality of streams in some areas is greatly impaired by color and turbidity. Heavy concentrations of sediment may be found in all streams draining the upland reaches of the state, especially during storm periods. Additionally, contaminants become concentrated during periods of low flow.

In an effort to inhibit further degradation and reduce present pollution levels, the surface water bodies of the

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[20] U.S. Environmental Protection Agency, Guidelines for Air Quality Maintenance, Planning, and Analysis, Volume 14: Designated Air Quality Maintenance Areas, EPS-450/4-75-002, December 1975.

[21] Louisiana State Planning Office, The State of the State in 1976.

TABLE J-26

## ESTIMATED ATTAINMENT OF NATIONAL TSP AND $SO_2$ AMBIENT AIR QUALITY STANDARDS BY AIR QUALITY CONTROL REGION[1]

(LOUISIANA)

| AQCR | Probably will attain | Probably will not attain | Attainment status uncertain |
|---|---|---|---|
| *019. Monroe-El Dorado Interstate (Arkansas) | TSP[2]<br>$SO_2$ | | |
| *022. Shreveport-Texarkana-Tyler Interstate (Ark., Okla., Texas) | $SO_2$ | TSP[2]<br>Point sources | |
| *106. Southern Louisiana-Southeast Texas Interstate (Texas) | $SO_2$ | | TSP[2]<br>Point and non-point sources |

* = Interstate AQCR

[1] Attainment is based on most recent air quality data available; these do not, in all cases, reflect final compliance. Estimated attainment status for both TSP (total suspended particulate) and $SO_2$ (sulfur dioxide) is based on annual and/or 24-hour averages. Comments noting factors that prevent attainment are occasionally included in the last two columns; these comments, like the attainment status, are best estimates and/or judgements.

[2] Estimated attainment status for this pollutant is different in another State portion of this interstate AQCR.

# TABLE J-27

## NUMBER OF STATIONS REPORTING AND NUMBER OF STATIONS AT WHICH STANDARDS WERE EXCEEDED, BY AQCR, 1970-1974
## (LOUISIANA)

| AIR QUALITY CONTROL REGION | YR | SUSPENDED PARTICULATES | | | | | | SULFUR DIOXIDE | | | | | CARBON MONOXIDE | | | OXIDANTS | | NITROGEN DIOXIDE | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | ANNUAL | | | 24-HOUR | | | ANNUAL | | 24-HR | | 3-HR | | 1-HR | 8-HR | | 1-HR | | |
| | UG/CU.M<br>P.P.M | # STA (1) | #> SEC 60 | #> PRI 75 | # STA (2) | #> SEC 150 | #> PRI 260 | # STA (1) | #> STD 80<br>.03 | # STA (2) | #> STD 365<br>.14 | #> STD 1300<br>.50 | # STA (2) | #> STD 40*<br>35 | #> STD 10*<br>9 | # STA (2) | #> STD 160<br>.08 | # STA (1) | #>AN STD 100 |
| 019 MONROE-EL DORADO (ARK-LA) | | ( 3) | | | | | | ( 1 + 0) | | | | | ( 0) | | | ( 0) | | ( 0) | |
| | 70 | 0 | 0 | 0 | 2 | 1 | 0 | 0 | 0 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | 71 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | 72 | 4 | 3 | 2 | 6 | 2 | 0 | 1 | 0 | 2 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | 73 | 3 | 1 | ? | 7 | 4 | 0 | 1 | 0 | 3 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | 74 | 5 | 2 | 1 | 6 | 1 | 0 | 3 | 0 | 3 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 0 |
| 022 SHREVEPORT-TEXARKANA-TYLER (ARK-LA-OKLA-TEX) | | ( 3) | | | | | | ( 1 + 0) | | | | | ( 0) | | | ( 0) | | ( 0) | |
| | 70 | 3 | 3 | 1 | 7 | 5 | 1 | 0 | 0 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | 71 | 3 | 2 | 1 | 6 | 2 | 1 | 1 | 0 | 2 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | 72 | 5 | 4 | 3 | 11 | 3 | 0 | 3 | 0 | 3 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | 73 | 6 | 3 | 1 | 11 | 4 | 0 | 2 | 0 | 6 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | 74 | 5 | 4 | 1 | 18 | 3 | 0 | 3 | 0 | 7 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 0 |
| 106 SOUTHERN LOUISIANA-SOUTHEAST TEXAS (LA-TEX) | | ( 3) | | | | | | ( 11 + 6) | | | | | ( 0) | | | ( 6) | | ( 0) | |
| | 70 | 8 | 4 | 1 | 6 | 0 | 0 | 3 | 0 | 4 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | 71 | 7 | 7 | 1 | 14 | 2 | 1 | 2 | 0 | 4 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | 72 | 8 | 6 | 3 | 10 | 2 | 0 | 11 | 0 | 16 | 0 | 0 | 3 | 0 | 1 | 4 | 4 | 0 | 0 |
| | 73 | 11 | 4 | 3 | 20 | 4 | 2 | 11 | 0 | 22 | 0 | 0 | 1 | 0 | 1 | 2 | 2 | 0 | 0 |
| | 74 | 6 | 3 | ? | 20 | 1 | 0 | 13 | 0 | 28 | 0 | 0 | 3 | 0 | 1 | 3 | 2 | 2 | 0 |

(1) NUMBER OF STATIONS REPORTING A FULL YEAR'S VALID DATA
(2) NUMBER OF STATIONS REPORTING AT LEAST 3 24-HR VALUES OR 400 HOURLY VALUES
? STATIONS WITH INCOMPLETE DATA MAY BE EXCEEDING THE ANNUAL STANDARD; SEE APPENDICES
* CO STANDARDS ARE IN MILLIGRAMS PER CUBIC METER

state have been designated as either effluent limited or as water quality limited by the Louisiana Stream Control Commission (Figure J-53). Water bodies classified as effluent limited are within acceptable water quality standards. Discharges into these streams and lakes must meet or exceed existing standards to be permitted. Surface water features classified as water quality limited are subjected to more stringent controls. The water bodies of this category are polluted, and further discharges polluting these streams and lakes are not permitted. New discharges must be treated to conform to or exceed existing water quality levels.

### Groundwater Quality[22]

Although large amounts of ground water underlie Louisiana, the state is faced with a growing number of problems. One problem is saltwater encroachment due primarily to heavy irrigation pumpage. Along with the problem of saltwater encroachment goes the potential problem of contamination of freshwater by salt domes and surficial "salt licks." Salt domes are concentrated largely in southern Louisiana, although a fairly large number occur in the parishes immediately east of the Red River Valley and also in a few parishes adjacent to the Mississippi River. In areas of shallow alluvial and terrace deposits, surface disposal of wastes is a critical problem.

Iron and hardness are a persistent problem over much of the state. Other constituents that are found to be present locally in the water in objectionable quantities include fluoride, silica, sulfate, and chloride. Other sources of contamination present in some areas of the state include methane and hydrogen sulfide gas and oilfield brines.

Methane concentrations in freshwater aquifers range from zero to 127 mg/l. The areas of largest methane concentrations occur in the vicinity of three oil- and gas-producing fields and in some wells in the vicinity of Lake Charles where continuous pumping has lowered water levels greatly. Generation of methane from organic matter within the freshwater aquifers and intrusion of methane into the aquifers from underlying oil and gas sands are two possible sources of this gas.

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[22] M.R. Scalf et al., Ground Water Pollution in the South Central States, U.S. Environmental Research Center, Office of Research and Monitoring, Environmental Protection Technology Series, EPA-R2-73-268.

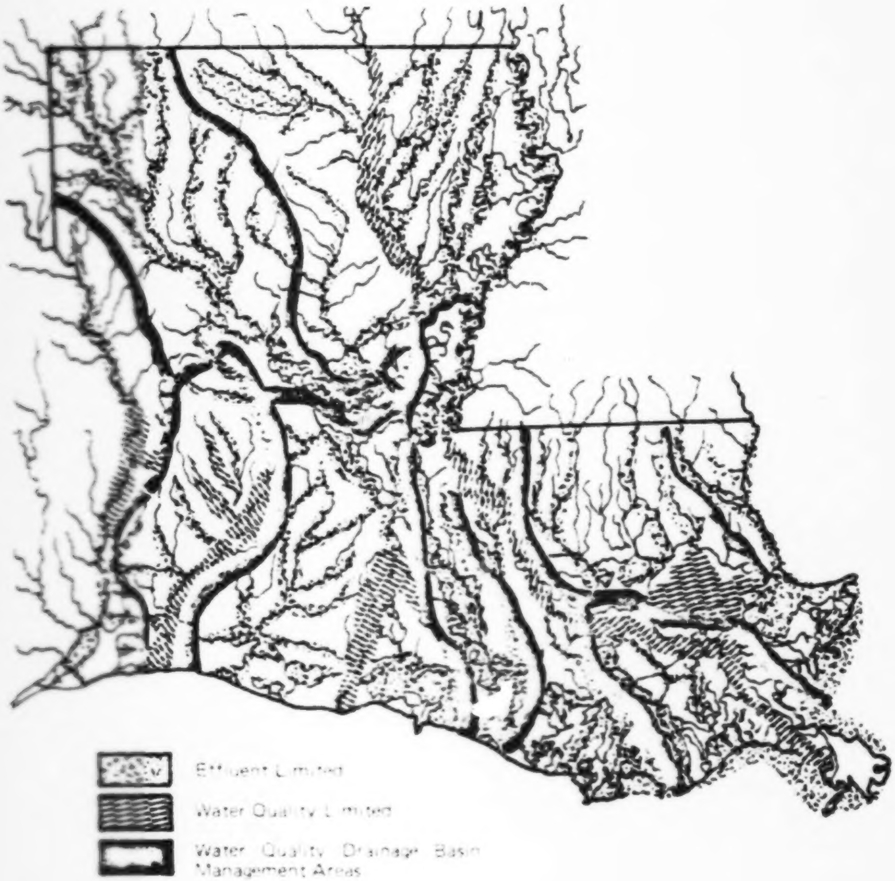
Effluent Limited
Water Quality Limited
Water Quality Drainage Basin Management Areas

Figure J-53. Surface water features (stream control) of Louisiana. (Louisiana State Planning Office, The State of the State in 1976, Figure 5-2, p. 60, from USGS, Louisiana Stream Control Commission.)

## 6. Wyoming

### 6.1 Physiography and Climate

#### Physiography

Wyoming is a region of considerable physiographic diversity including high mountain ranges, steep river valleys, foothills, narrow terraces, plains, rolling hills, badlands, and uplifts. The state can be divided into four major physiographic provinces -- the Middle Rocky Mountains in the west and northwest, the Southern Rocky Mountains extending into the southeast, the centrally located Wyoming Basin, and the eastern Great Plains.

The Continental Divide, beginning near the center of Wyoming's southern boundary, extends through Wyoming in a north-westerly direction, separating the Missouri River basin (to the northeast) from the Colorado and Columbia River basins (to the southwest and west respectively). In south-central Wyoming the Continental Divide splits to encircle a closed drainage basin, the Great Divide Basin.

Approximately one-third of Wyoming is mountainous; the remaining two-thirds being basins and plains. The mean elevation is about 6,700 feet; topographic elevations vary from 3,100 to 13,785 feet above sea level. Wyoming straddles the Continental Divide and provides the headwaters of four major river basins of the West -- the Missouri, the Colorado, the Great Basin, and the Columbia.

#### Climate

The climate of Wyoming is a product of its latitude, elevation and topography. The state is in the latitude of the prevailing westerlies with a dominance of maritime Pacific air. This air is modified by the several mountain ranges between Wyoming and the West Coast which cause low-level moisture to be precipitated before reaching the state. Precipitation, chiefly in the form of snow, ranges from 20 to more than 40 inches per year in the higher mountain ranges. The eastern plains areas of the state

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Note: All information in this section (unless otherwise footnoted) was taken from: State Engineer's Office, Wyoming Water Planning Program, The Wyoming Framework Water Plan, May 1973.

receive from 9 to 16 inches of precipitation annually, falling mainly between April and July. The desert basins in the western part of the state normally receive 6 to 9 inches of precipitation per year.

Wind is an important factor of the Wyoming climate. This is largely due to the high elevation and the enormous stretches of rolling plains. Over the higher south portions average annual wind speeds range from 5 to 6 meters per second. Much of the north portion, being considerably lower in elevation, has a lower average speed. There are some favorable locations which are protected from the wind by mountain ranges. Lander is one such place and has an annual average of only 3 meters per second at the airport station. The records for the city of Lander show even lighter winds. The lower portion of the Big Horn Basin at such places as Wyoming is quite windy, and during the colder months from November through March there are frequent periods when the wind reaches 13 to 18 meters per second with occasional gusts much higher. Prevailing directions in the different locations vary from west-scuthwest through west to northwest.[1]

A survey of stations reporting wind speed distribution (as reported to the National Climate Center) indicates that an average of 12 percent of the hourly observations fall into the lowest wind speed class, with winds less than 1.5 meters per second. The variability between the stations, however, is quite large due to the factors indicated above. For example, the Cody airport terminal reported an average low wind speed occurrence to be 0.6 percent, while Riverton reported an average of 32 percent.

## 6.2 Population and Economy

### Population

The census figures for 1970 place Wyoming's population at 332,416. Population density is correspondingly low, averaging 3.4 people per square mile. Urbanization is increasing, although it falls below the national average. Approximately 60.5 percent of the population is urban, with rural nonfarm and farm populations contributing 29 percent and 10.5 percent of the population, respectively.

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[1] A.R. Lowers, "The Climate of Wyoming," in Climates of the States, Volume II (Port Washington, N.Y.: Water Information Center, Inc., 1974).

The percentage of the Wyoming population below the poverty level (11.7 percent) is lower than the national average of 13.7 percent. Unemployment, based on 1974 figures, was 3.6 percent compared to the national average of 5.6 percent for the same year. Employment by basic industries (1970 figures) was:

| | |
|---|---|
| agriculture, forestry and fishing | 9.5 percent |
| mining | 8.5 percent |
| construction | 6.6 percent |
| manufacturing | 6.1 percent |
| other primary services | 64.5 percent |

## Economy

The Wyoming economy is greatly dependent on the mineral industries. Employment and accompanying payroll are of primary economic importance. In terms of taxes collected in the state, mineral production is Wyoming's most important industry. For the fiscal year ending June 30, 1971, the total taxes, royalties, and state rental fees paid were over $64.5 million; total value of Wyoming's mineral production was $705.5 million in 1970.

Wyoming has very little manufacturing to serve as a market for mineral products; the mineral industry relies on the production of raw materials that can be shipped to distant market centers and yet be competitive. Wyoming's fuel minerals include oil and gas, coal, uranium, and oil shale. The oil and gas industry is presently the largest part of Wyoming's mineral industry.

Since the petroleum industry is an extractive one with finite resources, it is projected to decline beginning around 1980. Oil fields are found in the northeastern counties of Campbell, Crook, and Weston and in the western central counties of Sublette and Fremont. Oil fields are also found in Natrona, Converse, and Niobrara Counties. Counties where tertiary recovery techniques are used or are technically feasible include Campbell, Crook, Weston, Converse, Johnson, Fremont, Sublette, and Uinta (see Figure J-54).

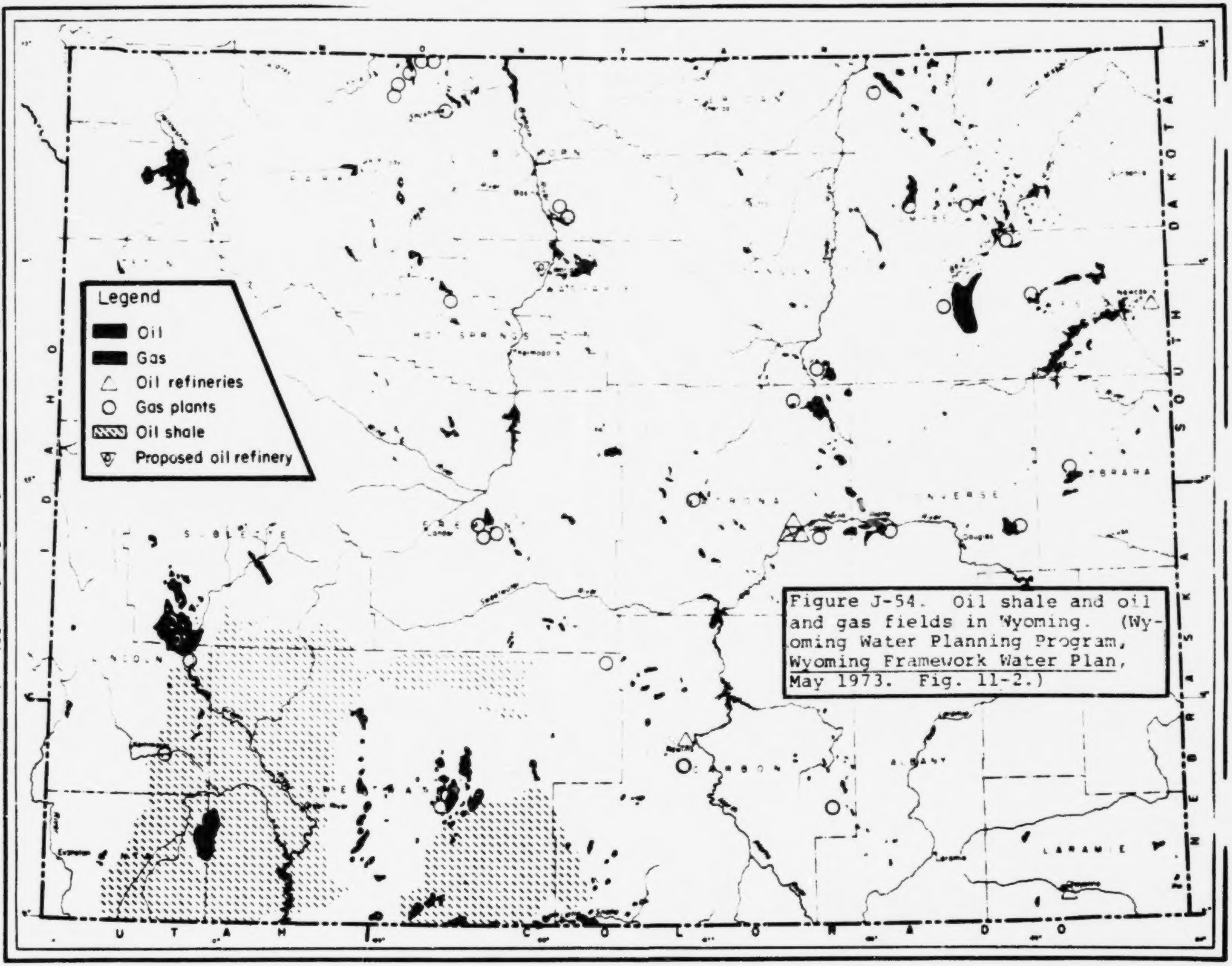

Legend
Oil
Gas
Oil refineries
Gas plants
Oil shale
Proposed oil refinery
M O N T A N A
I D A H O
U T A H
C O L O R A D O
S O U T H D A K O T A
N E B R A S K A
HOT SPRINGS
SUBLETTE
LINCOLN
NATRONA
CONVERSE
CARBON
ALBANY
LARAMIE
NIOBRARA

Figure J-54. Oil shale and oil and gas fields in Wyoming. (Wyoming Water Planning Program, Wyoming Framework Water Plan, May 1973. Fig. 11-2.)

Note: Color copy available for viewing at FEA Freedom of Info. Office in Washington, D.C.

Agricultural activities presently use about 84 percent of Wyoming's approximate 62.3 million acres of land area. About 94 percent of agricultural land is used for livestock grazing by cattle and sheep. A little more than 5 percent of the available agricultural land is used as cropland; more than 62 percent of this land is under vegetation. In practically all areas of the state, irrigation is necessary for dependable crop production.

Major sources of income for Wyoming ranch and farm operators are livestock and associated products, which in 1970 accounted for 85 percent of the operators' gross cash receipts. Cattle is the largest source of income, followed by sheep and wool. In crop production, sugar beets contribute the most to gross cash receipts. In 1970, 6.1 percent of the total agricultural receipts were produced by sugar beets.

## 6.3 Resources

### Land

Land area in Wyoming is about 62.3 million acres, while the water area is approximately 404,950 acres. About 54 percent of the land acreage is owned by Federal, state, and local governments. Forty-three percent is owned by private interests, and 3 percent by Indian tribes. About 84 percent of the land area is taken up with agricultural activities. The remaining 16 percent of the land includes the national park systems, recreation areas, inhabited areas, roads and highways, Federal lands where livestock grazing is not permitted for management purposes, and other areas of non-agricultural use.

About one-seventh of Wyoming is covered by timber, almost all of which occurs in national forest areas. Wyoming is characterized by vast open spaces, rolling hills, badlands, benchlands, prairies, foothills, and mountains. The majority of the land is semiarid to arid, with prime water-producing areas occurring in mountainous regions.

### Surface Water

Wyoming surface waters have been organized into seven drainage basins that fall into four major river basins. The Yellowstone, Bighorn, Northeastern Wyoming, and Platte River Basins are in the Missouri River Basin. The Green River

Basin is considered a part of the Wyoming Colorado River Basin. The Bear River Basin in Wyoming drains into the Great Salt Lake and falls into the area of the Great Basin. The Snake River Basin is the headwaters of the largest tributary of the Columbia River, and as such, is a part of the Columbia River Basin (see Figure J-55).

Streams, lakes, and reservoirs constitute Wyoming's surface water resources. Streams flow primarily as a result of precipitation, although late summer, fall, and winter base flows are derived primarily from ground water. A major portion -- approximately 70 percent -- of the annual runoff in Wyoming's streams is snowmelt runoff occurring during the months of April, May, June and July. Variations in annual snowfall and other forms of precipitation from year to year can cause considerable variance from average annual stream flows.

Approximately 1.5 million acre-feet flow into Wyoming, and another 15.8 million acre-feet of water are accumulated within the state each year. Subtraction of the approximately 2.6 million acre-feet used annually within the state leaves 14.7 million acre-feet of water per year flowing into neighboring states. More than 82 percent of the annual streamflow depletion in Wyoming is used for irrigation; a little more than 2 percent is used for municipal, domestic, stock, and industrial purposes. Reservoir evaporation accounts for about 15 percent of the volume used annually within the state.

About 31 percent of the municipal population of Wyoming is supplied with surface water, with an additional 45 percent being served by a combination of surface water and ground water. Industry removes a little more than 1 percent of the total annual streamflow depletion.

There are many areas of the state where existing and potential water demands exceed local supplies. A diversion of water to the Gillette area in Northeastern Wyoming is needed in the near future, and water needs are expected to exceed available local supplies by 2,000 to 2,020 units. Expansion of irrigation will place additional demands on some regions, chiefly in the Platte and Green River Basins. Water shortages occur on the average of about 42 percent of irrigated lands. The basins of northeastern Wyoming and Bear and Snake Rivers have estimated annual water shortages on more than 59 percent of their irrigated lands.

## Ground Water

Sedimentary rock layers in Wyoming's basins are thousands of feet thick, approximately 30,000 feet in some places. Considering the approximately 200,000 cubic miles of rock formations present in Wyoming's basins, the total amount of ground water must be extremely large. However, the amount of ground water in storage is not an indication of its availability.

Figure J-55 indicates the regional occurrence and distribution of ground water in Wyoming. By observation and inference: (1) loose sands and gravels at shallow depths generally provide large well yields of fair-to-good quality water; (2) the middle and late Tertiary sandstones at depths above 1,000 feet provide large well yields of good-quality water; (3) early Tertiary sandstones are very extensive and probably yield water to hundreds if not thousands of water wells, but yields are low and water quality is fair to poor; and (4) a limestone aquifer at intermediate drilling depths (3,000 to 8,000 feet) has the potential to provide very large well yields and very large quantities of water. Ground water is found at depths of more than two miles.

Most water wells in Wyoming are drilled to provide dependable water supplies for rural domestic and livestock uses. Many communities depend entirely on underground water for survival. Other communities use a combined water supply derived from both surface water and groundwater sources. The use of ground water for irrigation has increased dramatically during the past decade, principally in southeastern Wyoming. The mineral industries use large quantities of ground water, particularly in the secondary recovery of oil and the milling of uranium ore. Table J-28 lists the consumptive uses of ground water.

In 1970, about 8 percent of all water consumed by man's activities in Wyoming was ground water. This was an increase of 5 percent from 1965 figures and was due mostly to irrigation. Projections of a 15 percent usage rate for 2020 are based on potential industrial development, irrigation, and increased tourism.

## Energy

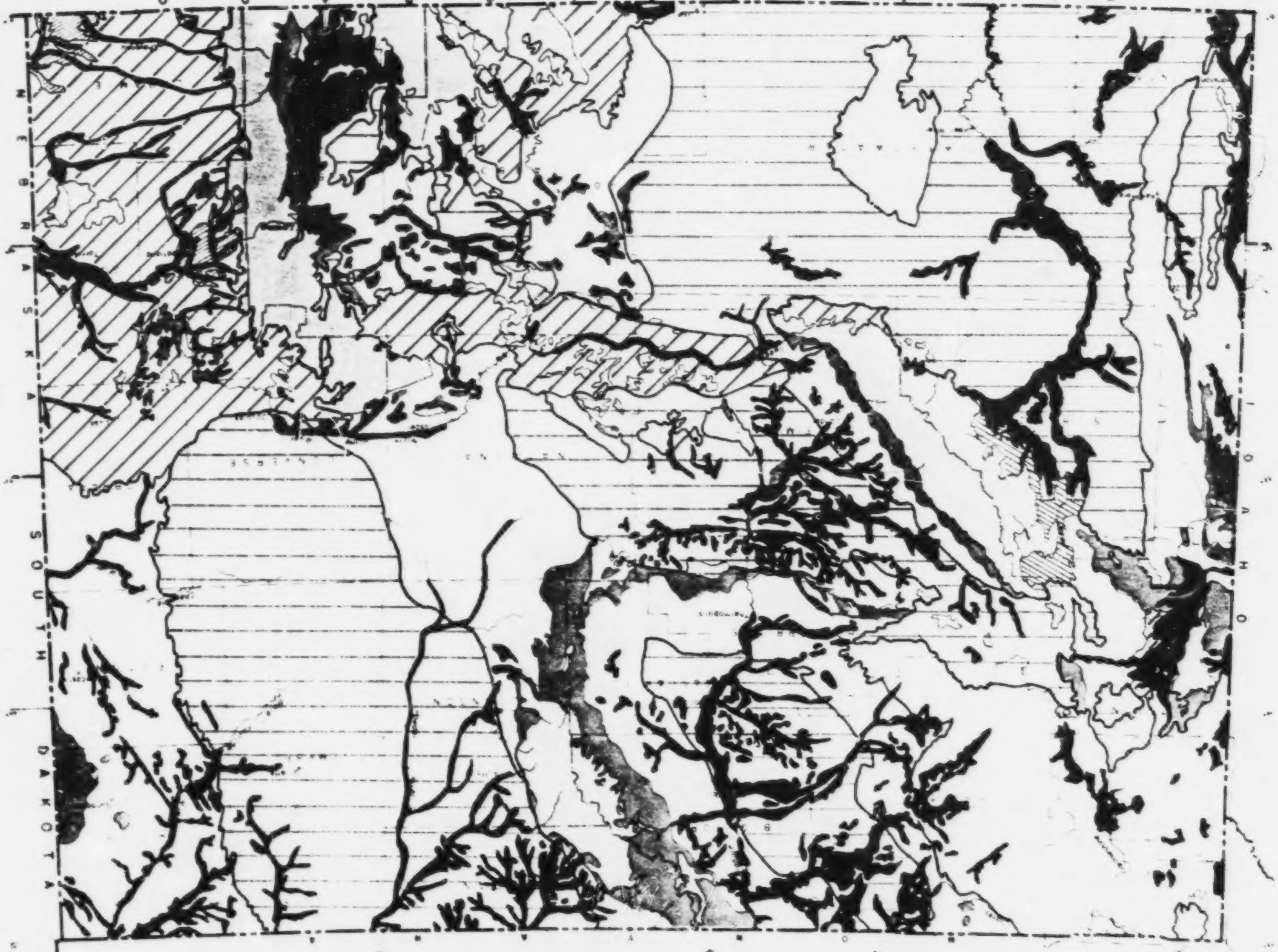
In 1973, total installed generating capacity for Wyoming was 1,885 thousand kilowatts. About 86 percent of

# TABLE J-28

## CONSUMPTIVE USES OF GROUND WATER IN WYOMING IN 1972 IN ACRE-FEET/YEAR

| BASIN OF AREA | IRRIGATION | MUNICIPAL, DOMESTIC, AND LIVESTOCK | INDUSTRIAL | TOTAL |
|---|---|---|---|---|
| Yellowstone | -- | -- | -- | -- |
| Bighorn River | 12,800 | 7,300 | 25,000 | 45,900 |
| Northeastern Wyoming | 8,700 | 8,100 | 16,800 | 33,600 |
| Platte River | 106,000 | 13,700 | 3,000 | 122,700 |
| Green River | 1,200 | 1,200 | 4,400 | 6,800 |
| Bear River | 4,100 | 400 | 400 | 4,900 |
| Snake River | 700 | 1,400 | -- | 2,100 |
| TOTAL | 133,500 | 32,100 | 50,400 | 216,000 |

J-156


IDAHO
UTAH
COLORADO
NEBRASKA
SOUTH DAKOTA
Thermopolis

J-156

Note: A color copy of this diagram is available for viewing at the FEA Freedom of Information Office in Washington, D.C.

|  |  | Well Yield (GPM) |  | Drilling Depth (Feet) |  | Total Dissolved Solids (PPM) |  |
|---|---|---|---|---|---|---|---|
|  |  | Median Range | Maximum Reported | Median Range | Maximum Reported | Estimated Median | Reported Range (Water Wells) |
| Valley Alluvium | ■ | 50-500 | 3,000 | 10-100 | 300 | 500 | 20-3,500 |
| Terrace Alluvium | ▨ | 150-500 | 1,500 | 10-80 | 160 | 400 | 230-800 |
| Late & Middle Tertiary | ▧ | 150-800 | 2,000 | 100-600 | 1,000+ | 600 | 175-4,900 |
| Early Tertiary | ☰ | 1-50 | 1,000 | 40-300 | 3,000 | 1,500 | 160-7,000 |
| Cretaceous-Permian | □ | 1-20 | 900 | 200-2000 | 6,000 | 3,000 | 200-9000 |
| Pennsylvanian-Cambrian | ■ | 100-700 | 9,400 | 1,000-3,500 | 8,000 | 2,000 | 125-4,000 |
| Precambrian | □ | 1-5 | 15 | Outcrop (recharge) areas |  | 250 | 50-500+ |

□ *Igneous and metamorphic rocks, mostly of volcanic origin--- no data*

▨ *Glacial deposits---no data*

*FIGURE I-9a*
*Major Geologic Basins*
*(from Wyoming Geological Association Guidebook)*

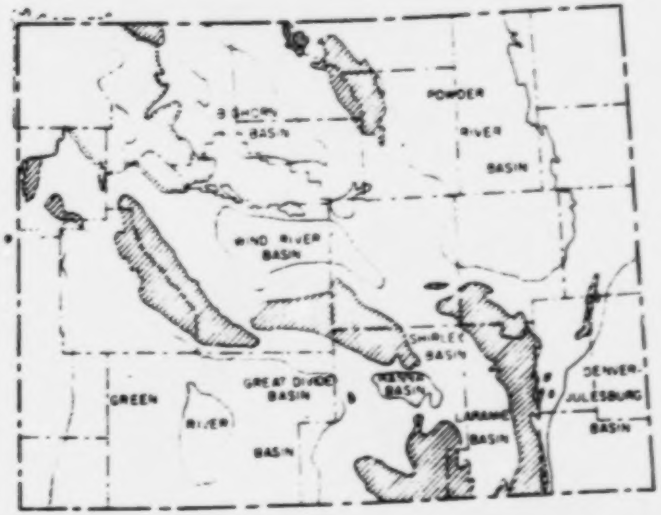
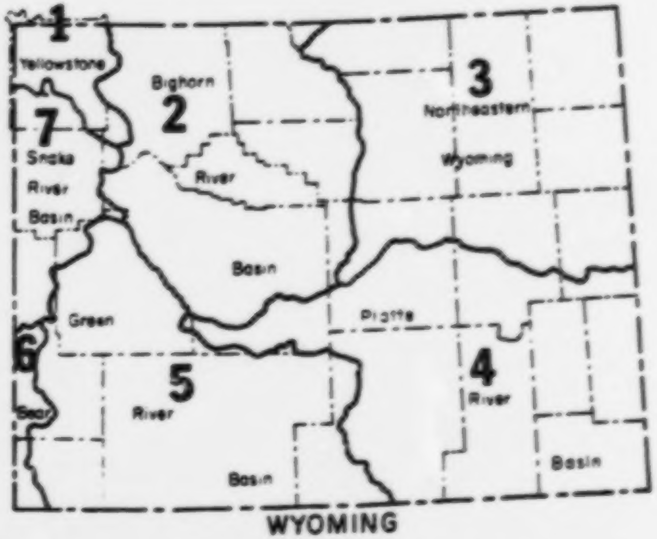

BIGHORN BASIN
POWDER RIVER BASIN
WIND RIVER BASIN
SHIRLEY BASIN
GREAT DIVIDE BASIN
HANNA BASIN
LARAMIE BASIN
DENVER-JULESBURG BASIN
GREEN RIVER BASIN

*FIGURE I-9b*
*Drainage Basins or Areas*


1
Yellowstone
2
Bighorn
River
Basin
3
Northeastern
Wyoming
4
Platte
River
Basin
5
Green
River
Basin
6
Bear
7
Snake
River
Basin
WYOMING

. Note: A color copy of this diagram is available for viewing at the FEA Freedom of Information Office in Washington, D.C.

Figure J-55. Water yielding capabilities of rock units in Wyoming. (Wyoming Water Planning Program, Wyoming Framework Water Plan, May 1973. Fig. 1-9a and Fig. 1-9b.)

this capacity resides in fossil fuel-powered electric utilities; the remaining 14 percent is divided between hydroelectric facilities (approximately 12 percent) and industrial plants (approximately 2 percent). There are no nuclear power plants in Wyoming.

### Wildlife and Recreation

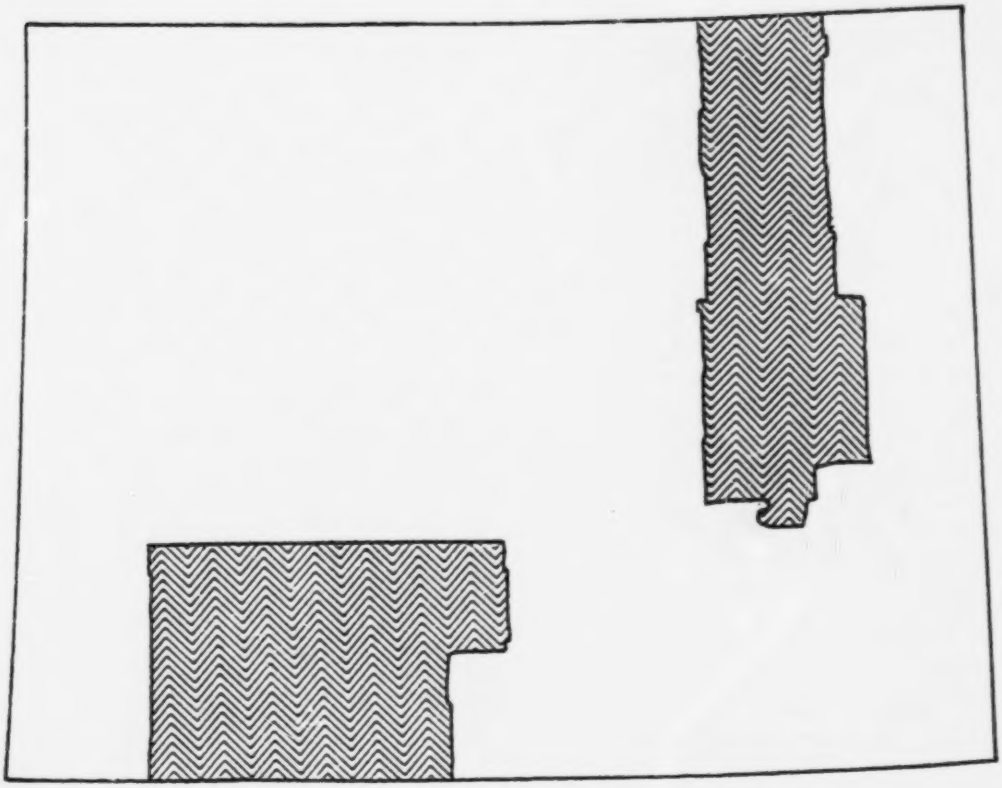
Wyoming's wildlife resources include abundant numbers of antelope, deer, elk, moose, black bear, bighorn sheep, upland game, and small game. This wildlife as well as many other animal species, birds, and waterfowl are dependent upon the land and water for habitat.

The scenic beauty of Wyoming's open spaces, rugged mountains, forests, and natural parks has led to an important and growing tourist enterprise. Two national parks, Yellowstone and Grand Teton, attract large numbers of tourists every year. Six national forests within the state contain pine, fir, and spruce. Hunting and fishing contribute substantially to the state's economy. Total expenditures by nonresidents for fishing and hunting in 1970 were $8.5 and $19.2 million respectively. Resident fishermen contributed $15.7 million, and resident hunters spent $14.1 million. A number of Wyoming's rivers have been considered for designation as scenic rivers.

## 6.4 Environmental Quality

### Air Quality

There are two air quality maintenance areas in Wyoming, the Powder River Basin and Sweetwater AQMA's (see Figure J-56). They include Campbell, Converse, and Sweetwater Counties. Both areas suffer from particulate problems. The Powder River Basin AQMA is expected to contain substantial levels of photochemical oxidants, while the Sweetwater AQMA requires additional controls on sulfur dioxide pollution since it is an industrial development area. Both of these regions contain oil production activity. Furthermore, Wyoming has been called upon to revise its clean air implementation plan with respect to particulate matter control practices. Strategies for controlling a wider range of sources contributing to the ambient concentration of particulates is thought to be required. No data on the attainment status of the other pollutants are available. Wyoming's ambient air quality standards follow those applied on the national scale



| AQMA | AQMA Number | POLLUTANTS | | | | |
|---|---|---|---|---|---|---|
| | | PM | $SO_2$ | CO | $O_X$ | $NO_2$ |
| Wyoming | | | | | | |
| Powder River Basin – Natural Resource Development Area | 241A | X | | | X | |
| Sweetwater – Natural Resource Development Area | 243A | X | X | | | |

Figure J-56. Wyoming Air Quality Maintenance Areas. (U.S. Environmental Protection Agency, Guidelines for Air Quality Maintenance Planning and Analysis, Volume 14: Designated Air Quality Maintenance Areas, December 1975, Figure 52, p. 176.)

(see NAAQS listing in Table J-13) except for particulates and sulfur dioxide. Particulate concentrations are gauged against the Federal secondary standards, while those for sulfur dioxide are 60 $\mu g/m^3$ for the annual mean, and 260 $\mu g/m^3$ for the 24-hour mean. The Federal secondary standard for the mean 3-hour sulfur dioxide concentration is adopted without modification.

## Surface Water Quality

In general, the water in Wyoming's streams is of excellent quality. Unlike more heavily populated regions, municipal and industrial water quality degradation is a minor problem. Areas of poor water quality occur below Thermopolis in the Bighorn Basin, below Evanston in the Bear River Basin, and in the Snake River Basin. These are the only notable point sources of pollution. Non-point source pollution problems are more significant in the state, particularly in the Northeastern Wyoming River Basin. Turbidity and sedimentation problems arise from natural runoff. In a few areas, mainly the Bear River and Platte River Basins, irrigation return flows also contribute to water quality degradation. Salinity is not considered to be a water quality problem in Wyoming. Only minor pollution problems related to oil fields exist; oil spills and pipeline breaks have occasionally caused pollution problems in the Bighorn Basin.

## Groundwater Quality

The chemical quality of ground water is a variable that must be considered in an evaluation of the supply. According to U.S. Public Health Service Standards (1962), water for human consumption should have no more than 1,000 parts per million (ppm) total dissolved solids (TDS) and preferably no more than 500 ppm. Many people in Wyoming use ground water with TDS concentrations greater than 1,000 ppm. Even though the ground water contains soluble salts in objectionable concentrations, it is used because no better water supply is available. Its use continues because people become accustomed to it. Livestock can use water of higher TDS concentrations (an upper limit of 5,000 ppm is recommended by some investigators).

The median TDS concentration in ground water in sands and gravels and sandstone above a depth of 1,000 feet in Wyoming is about 500 ppm. In deeper aquifers, to a depth of 8,000 feet, the median TDS concentration is 2,000+ ppm. The concentration in waters produced from clays and shales commonly is in the range 2,000 to 10,000 ppm. Higher TDS concentrations are reported from water produced by oil exploration wells. The maximum reported TDS concentration is 200,000 ppm in water associated with accumulations of petroleum in the Powder River Basin (see Figure J-55).

Hardness is caused primarily by high concentrations of calcium and magnesium in water. The aquifers that are widely used in Wyoming provide mostly hard water. Ground water in the alluvium generally is moderately hard (60 to 120 ppm) to very hard (200+ ppm). In consolidated aquifers it is soft (0 to 60 ppm) to very hard, with extreme variations in the same aquifer. Water in Cretaceous and Jurassic sandstones usually is not as hard as water in younger (Tertiary) and older (Triassic through Cambrian) aquifers.

## 7. Oklahoma

### 7.1 Physiography and Climate

#### Physiography

Oklahoma lies in a transitional zone in topography, so that its landscape is quite diverse. Three of the nation's large physical regions extend into or across the state. The Interior Highlands is in the east; the Coastal Plain is in the south; and the Interior Plains, including the Central Lowland and Great Plains, cover the remainder of the state. Elevation ranges from 287 to 4,973 feet; approximate mean elevation is 1,300 feet.

#### Climate

The climate in Oklahoma is mostly of the continental type characteristic of the central Great Plains. Summers are long and hot; winters are less rigorous than those of more northern plains states. Moist air currents from the Gulf of Mexico influence the weather during most of the year, although cool, moist air masses from the Pacific and cold, dry air masses from Canada predominantly influence the weather during the winter months. Maximum precipitation occurs in the spring, decreasing through the summer months. Maximum secondary precipitation occurs in the fall. May is usually the wettest month and January the driest.

Annual rainfall decreases sharply from east to west. Average annual precipitation ranges from about 56 inches in southern LeFlore County in the southeastern corner of the state to approximately 15 inches in the western section of the Panhandle. Runoff varies dramatically across the state, with values falling between 0.2 inches in the Panhandle to 20 inches in the southeast corner. Western Oklahoma is subject to long dry periods and frequent floods.

Prevailing winds are southerly, although northerly winds predominate during the winter months. Average yearly wind speeds vary from 4 meters per second in the east to over 6 meters per second in the west. March and April are

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Note: All information in this section (unless otherwise footnoted) was taken from: Oklahoma Water Resources Board, Oklahoma Comprehensive Water Plan, Phase I, Sept. 1, 1975.

the windiest months, and July and August the calmest.[1] Stations reporting wind speed distributions to the National Climate Center indicate that 7 percent of the hourly observations fall into the lowest wind speed class of less than 1.5 meters per second. No significant east-west or north-south pattern is discernable from the 10 locations considered.

## 7.2 Population and Economy

### Population

Oklahoma City and Tulsa contain approximately 49 percent of Oklahoma's 1970 population of 2.6 million. Sixty-eight percent of the population in Oklahoma is urban. The trend is toward population concentration; between 1940 and 1970, the number of cities and towns with a population of more than 2,500 increased from 74 to 100.

### Economy

In 1972, 2,911 industries contributed over $1.1 billion to the Oklahoma payroll. Oklahoma ranks 33rd among all states in industry. Leading major industry groups in value added by manufacture were machinery (except electrical), food, and fabricated metal.

In 1973 there were 72,900 producing oil wells in Oklahoma. Production in 1973 was 191 million barrels of crude petroleum, representing a value of about $723 million. Proved oil reserves for the same year were 1,232 million barrels. Counties where tertiary oil recovery techniques are technically feasible include Carter, Creek, Lincoln, Osage, and Stephens counties (see Figure J-57).

Of Oklahoma's total land area of 43,819,111 acres, 12,992,641 acres (approximately 30 percent) are in cropland. About 43 percent of the total land area is used for range and pastureland; and about 20 percent is in forestland. Total irrigated acreage as estimated by Oklahoma State University Service is 758,036, most of which is in western Oklahoma.

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[1] W.R. Curry, "The Climate of Oklahoma," in Climates of the States (Port Washington, N.Y.: Water Information Center, Inc., 1974).

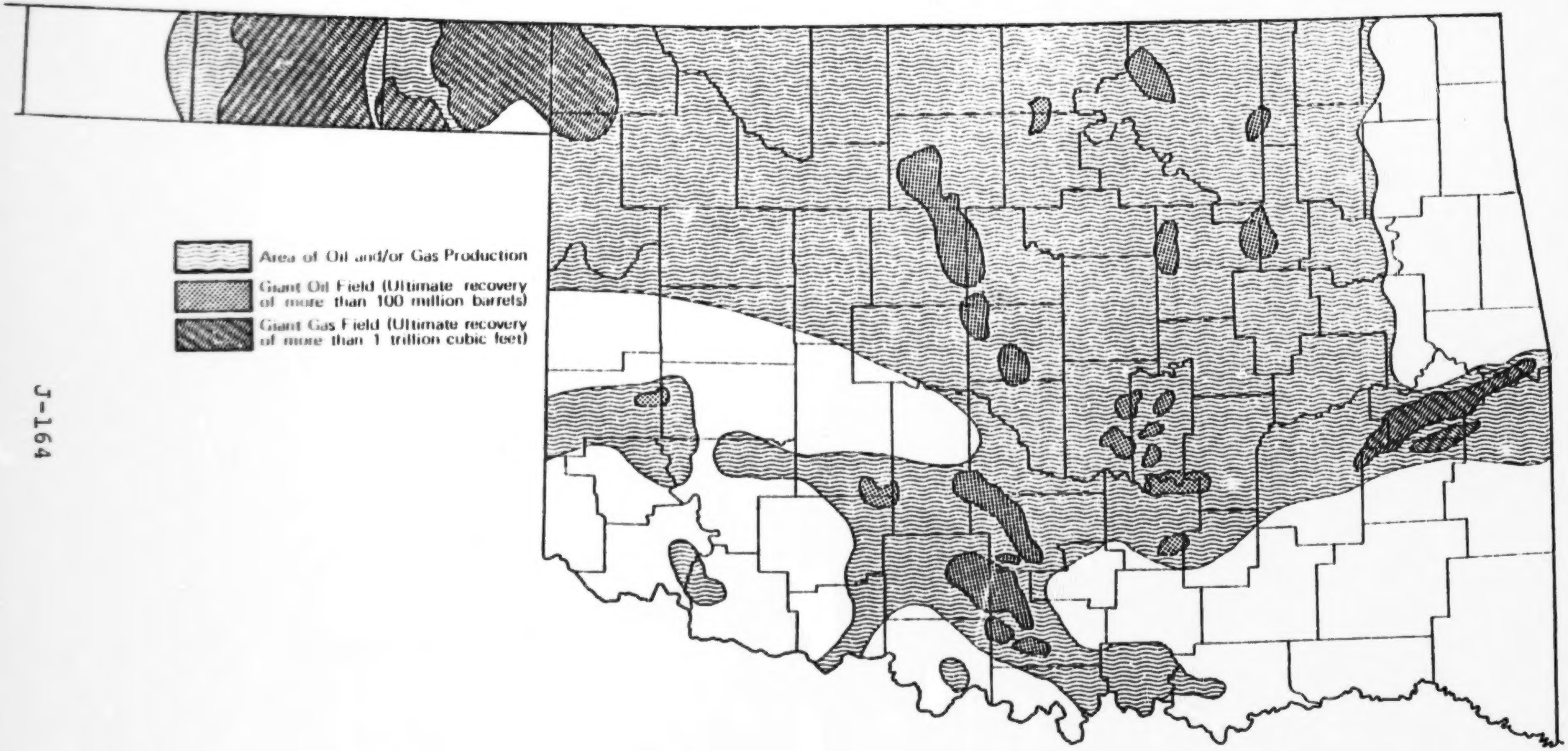

Area of Oil and/or Gas Production
Giant Oil Field (Ultimate recovery of more than 100 million barrels)
Giant Gas Field (Ultimate recovery of more than 1 trillion cubic feet)

Figure J-57. Composite map of Oklahoma oil and gas fields.

In 1972, livestock and products contributed about 78 percent of total revenue from farm production. Oklahoma currently ranks second in winter wheat and hay production. The value of principal crops and livestock had increased from $1,002 million in 1971 to a record $1,017 million in 1973. The principal agricultural industry in the state is beef, followed by wheat and dairy cattle. This predominance of beef production extends throughout western, central, and east central Oklahoma. East central and south central Oklahoma have thriving commercial timber and wood products industries.

Much of the state's industrial economy is dependent upon agriculture. These include food and allied products and agricultural supplies, materials, equipment and services, transportation and marketing. These agriculturally-oriented segments of the economy constitute a multi-billion dollar contribution to the total economy of the state. Direct employment in agriculture in 1972 was 125,000. In comparison, the total number employed in industrial activity was 151,000. Agriculture is the state's leading industry in terms of numbers of people employed. In terms of dollar volume, agriculture and petroleum are in close contention.

## 7.3 Resources

### Land

Pasture and range land represent by far the greatest use (42.3 percent) of land in Oklahoma. Non-irrigated and irrigated cropland account for 22.8 percent and 5.8 percent of the land respectively. Agricultural activities as a whole absorb about 72.4 percent of the available land surface. Forest land comprises about 19.6 percent of the land surface area. Only 3.4 percent is urbanized. Federal land holdings, at 2.4 percent, are only a little larger than surface water area (2.1 percent).

### Surface Water

Over the past quarter century, Oklahoma has developed an impressive system of artificial lakes. Most were designed as multi-purpose projects to allocate typical storage for flood control; power and conservation pools consisting of municipal, industrial, irrigation, water quality control; recreation; and fish and wildlife uses. During the past 25 years, 23 major lakes have been completed, and 3 more are currently under construction. In the 1920s, there were only 3 major lakes in Oklahoma; there are now more than 38.

Availability and quantity of water in Oklahoma follows a pattern of plenty in the east and insufficiency in the west. In many areas of the state, no water is available for appropriation. There are 8.4 million acres of land in western Oklahoma where all stream water has been allocated, making further municipal or irrigation water supply development impossible (see Figure J-58). No stream water is available for future needs and economic growth, and in some areas, water is insufficient to provide for the present.

Certain critical areas have some water available at times under certain conditions. Some 3.1 million acres have restrictions applicable to allocation of stream water specifying that water can only be captured or diverted during periods of high flow.

Agricultural demands for water exceed those of any other single industry. In 1970, irrigation accounted for 781,000 acre-feet of the total 1,518,700 acre-feet used in the state; municipal, domestic and rural water systems, and industrial, utility, and energy-related uses accounted for the remaining 737,700 acre-feet. About 90 percent of the total irrigation in Oklahoma occurs in the western half of the state. Ground water supplies about 83 percent of irrigation needs; storage and diversion of stream flow for irrigation is relatively constant. Future irrigation water requirements are expected to increase, since less than 10 percent of the irrigable land is currently irrigated. Energy-related water usage is also expected to increase. Secondary and tertiary recovery processes are expected to require increasing amounts of water. Oil refineries, coal gasification, and thermoelectric generation plants are expected to use more water with the increasing demands for energy.

## Ground Water

Twelve major groundwater basins occur in Oklahoma with an estimated 309 million acre-feet in storage. Not all water in storage is recoverable, however, due to technological, legal, and economic constraints. Recovery potential from Oklahoma groundwater basins ranges from 30 to 50 percent. Nearly one-half of the groundwater resources occur in the western part of the state, with average well yields of 300 gallons per minute (gpm). Central Oklahoma contains about

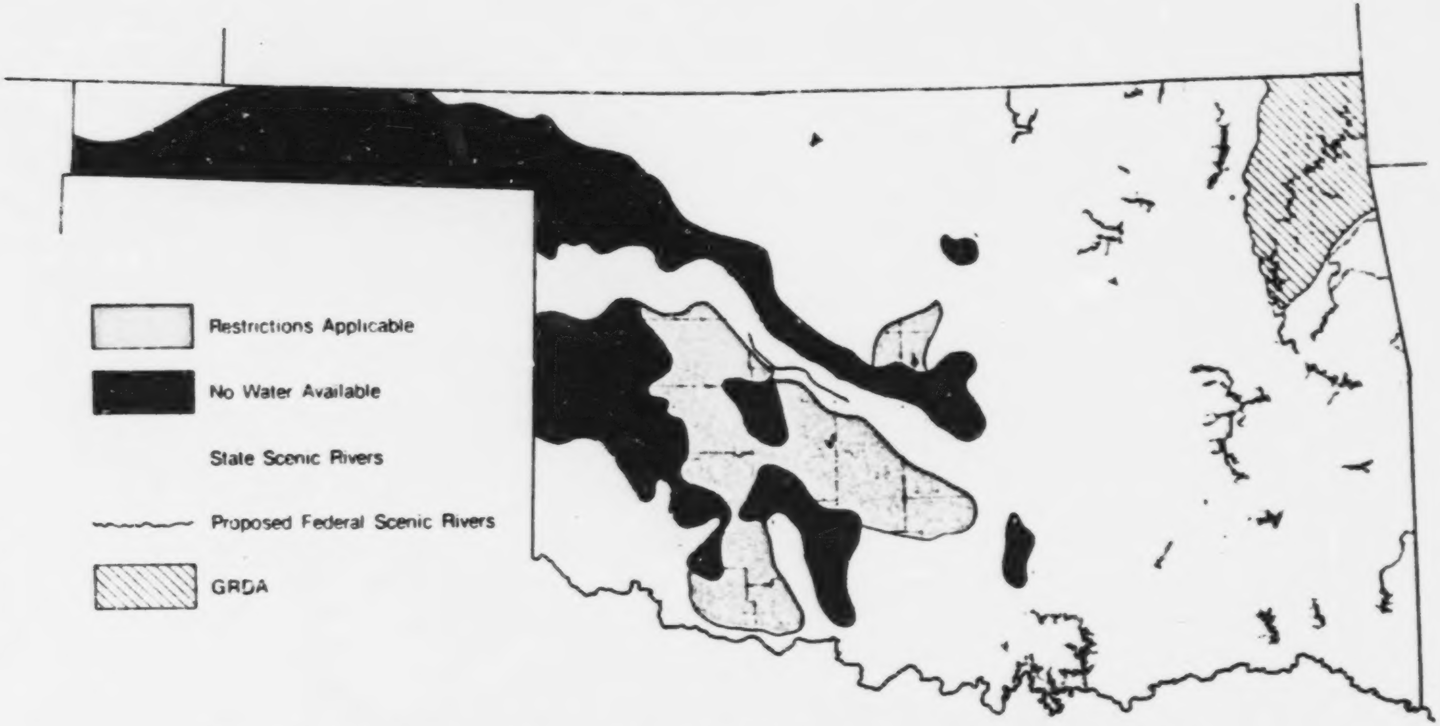

Restrictions Applicable
No Water Available
State Scenic Rivers
Proposed Federal Scenic Rivers
GRDA

Figure J-58. Stream water restrictions. (Oklahoma Water Resources Board, Oklahoma Comprehensive Water Plan, Sept. 1975, Figure 11-5, Resource chapter - p.4.)

Note: A color copy of this diagram is available for viewing at the FEA Freedom of Information Office in Washington, D.C.

one-third of the groundwater resources, and eastern Oklahoma accounts for roughly one-fourth; average well yields are 200 and 100 gpm, respectively.

Ground water is readily available in most areas of Oklahoma. It presently supplies 48 percent of the water used in the state. As previously mentioned, more than 80 percent of irrigation comes from groundwater reservoirs. Approximately 300 towns and cities obtain their water supplies from wells and springs. Groundwater development is greatest in the western part of the state where it is used extensively for irrigation, municipal and domestic needs. In contrast, ground water in central and eastern Oklahoma is used only by small towns and communities.

Overdevelopment of groundwater basins in Oklahoma (when pumpage exceeds recharge from precipitation) has occurred mainly in the western areas of the state. Major groundwater basins like the Tillman Terrace, Ogallala Formation and Rush Springs Sandstone are being dewatered; within the next 20 years, pumping may become financially infeasible.

## Wildlife and Recreation

There is not an area of Oklahoma that does not offer excellent hunting and fishing. The state is studded with well-stocked lakes and rivers, filled with a wide variety of freshwater fish. Hunting for small game is superb throughout the state and for large game, most areas offer whitetail deer. The dry, open northwest also has mule deer and antelope. There are many public hunting areas and wildlife refuges where unique species of animals are preserved. The Wichita Mountain Wildlife Refuge in the southwestern part of the state is one of four national refuges for buffalo, housing nearly 1,000 of this almost extinct species.

There are many scenic areas, rivers, and streams in Oklahoma, particularly in eastern portions of the state. The southeast sports the Talemena (Skyline) National Scenic Drive. Other attractions include the world's largest alabaster caverns (Woods County), Platt National Park, and numerous areas housing cowboy and Indian memorabilia.

## Energy

There are 10 existing hydroelectric plants in Oklahoma, with a total installed capacity of 800 megawatts. Fossil fuel-powered electrical generation supplies most of the state's energy needs, accounting for about 87 percent of the electric energy produced in 1973. Total installed fossil-powered electrical generating capacity is 5,500 megawatts.

## 7.4 Environmental Quality

### Air Quality

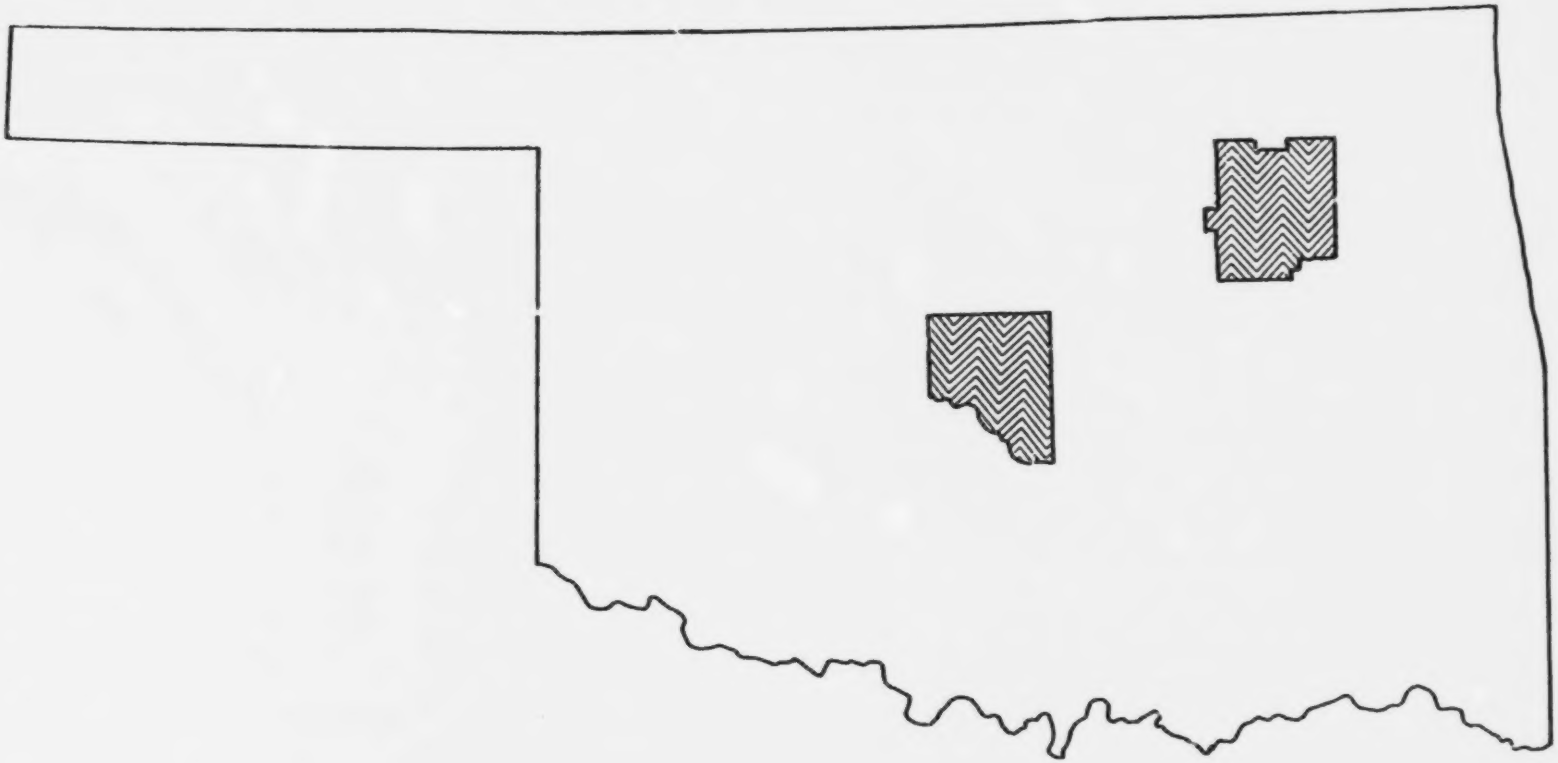
There are two air quality maintenance areas in Oklahoma, corresponding to the two major metropolitan areas of Oklahoma City and Tulsa. Figure J-59 indicates the two areas. Both experience difficulties with particulate matter and photochemical oxidants.

Table J-29 lists the most recent estimate of the status of attainment of the national ambient air quality standards for the year 1975. The evaluation includes only sulfur dioxide and particulates. Clearly, attainment problems are expected in some regions of Oklahoma for particulates as the result of eiter fugitive dust sources, or industrial point sources. Table J-30 gives an accounting of the 1974 monitor violations for all of the criteria pollutants. The state has not been called upon to revise its clean air implementation plan. Oklahoma's air quality standards are identical to the NAAQS listed in Table J-13.

### Surface Water Quality

Variability is a distinguishing characteristic of stream water quality in Oklahoma's two major river basins, the Arkansas and Red River stream systems. Variation is of two kinds, areal and that related to streamflow characteristics. The kinds and amounts of dissolved constituents which are predominant change radically from one end of the state to the other. Figure J-60 illustrates chemical water quality in terms of the discharge-weighted average concentrations of total dissolved solids.

As the Arkansas River crosses the state, the dissolved solids content of the water increases in the west and then decreases as it travels eastward. Tributary inflow with low dissolved solid content downstream from the Cimarron River markedly improves the quality. Two tributaries of the Salt Fork Arkansas River and the Cimarron River contain large amounts of dissolved solids from salt plains in their upper basins. This problem occurs at the western end of the Red



| AQMA | AQMA Number | POLLUTANTS | | | | |
|---|---|---|---|---|---|---|
| | | PM | $SO_2$ | CO | $O_X$ | $NO_2$ |
| **Oklahoma** | | | | | | |
| **Central Oklahoma** | **184A** | X | | | X | |
| **Tulsa** | **186A** | X | | | X | |

Figure J-59. Oklahoma Air Quality Maintenance Areas. (U.S. Environmental Protection Agency, Guidelines for Air Quality Maintenance Planning and Analysis, Volume 14: Designated Air Quality Maintenance Areas, December 1975, Figure 38, p. 131.)

TABLE J-29

## ESTIMATED ATTAINMENT OF NATIONAL TSP AND $SO_2$ AMBIENT AIR QUALITY STANDARDS BY AIR QUALITY CONTROL REGION[1]

(OKLAHOMA)

| | PROBABLY WILL ATTAIN | PROBABLY WILL NOT ATTAIN | ATTAINMENT STATUS UNCERTAIN |
|---|---|---|---|
| *017. Metropolitan Ft. Smith Interstate (Ark.) | TSP[2]<br>$SO_2$ | | |
| *022. Shreveport-Texarkana-Tyler Interstate (Ark., La., Texas) | TSP[2]<br>$SO_2$ | | |
| 184. Central Oklahoma | $SO_2$ | TSP - Point and non-point sources | |
| 185. North Central Oklahoma | TSP<br>$SO_2$ | | |
| 186. Northeastern Oklahoma | $SO_2$ | TSP - Point and non-point sources | |
| 187. Northwestern Oklahoma | $SO_2$ | TSP Fugitive dust area | |
| 188. Southeastern Oklahoma | TSP<br>$SO_2$ | | |
| 189. Southwestern Oklahoma | $SO_2$ | TSP Fugitive dust area | |

* = Interstate AQCR

[1] Attainment is based on most recent air quality data available; these do not, in all cases, reflect final compliance. Estimated attainment status for both TSP (total suspended particulate) and $SO_2$ (sulfur dioxide) is based on annual and/or 24-hour averages. Comments noting factors that prevent attainment are occasionally included in the last two columns; these comments, like the attainment status, are best estimates and/or judgements.

[2] Estimated attainment status for this pollutant is different in another State portion of this interstate AQCR.

## TABLE J-30

# NUMBER OF STATIONS REPORTING AND NUMBER OF STATIONS AT WHICH STANDARDS WERE EXCEEDED, BY AQCR, 1970-1974

## (OKLAHOMA)

| AIR QUALITY CONTROL REGION | YR | SUSPENDED PARTICULATES |  |  |  |  |  | SULFUR DIOXIDE |  |  |  |  | CARBON MONOXIDE |  |  | OXIDANTS |  | NITROGEN DIOXIDE |  |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
|  |  | ANNUAL |  |  | 24-HOUR |  |  | ANNUAL |  | 24-HR |  | 3-HR |  | 1-HR | 8-HR |  | 1-HR |  |  |
|  |  | # STA (1) | #> SEC | #> PRI | # STA (2) | #> SEC | #> PRI | # STA (1) | #> STD | # STA (2) | #> STD | #> STD | # STA (2) | #> STD | #> STD | # STA (2) | #> STD | # STA (1) | #>AN STD |
|  | UG/CU.M: |  | 60 | 75 |  | 150 | 260 |  | 80 |  | 365 | 1300 |  | 40* | 10* |  | 160 |  | 100 |
|  | P.P.M: |  | - | - |  | - | - |  | .03 |  | .14 | .50 |  | 35 | 9 |  | .08 |  |  |
| 017 METROPOLITAN FORT SMITH (ARK-OKLA) |  | ( 3) |  |  |  |  |  | ( 1 * 0) |  |  |  |  | ( 0) |  |  | ( 0) |  | ( 0) |  |
|  | 70 | 1 | 0 | 0 | 3 | 0 | 0 | 0 | 0 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
|  | 71 | 1 | ? | 0 | 4 | 2 | 1 | 1 | 0 | 2 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
|  | 72 | 1 | 0 | 0 | 8 | 1 | 0 | 1 | 0 | 2 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
|  | 73 | 6 | 3 | 1 | 8 | 3 | 0 | 1 | 0 | [illegible] | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
|  | 74 | 4 | 2 | 1 | 13 | 2 | 0 | 0 | 0 | 2 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 184 CENTRAL OKLAHOMA |  | ( 4) |  |  |  |  |  | ( 1 * 0) |  |  |  |  | ( 0) |  |  | ( 2) |  | ( 0) |  |
|  | 70 | 13 | 11 | 3 | 28 | 24 | 14 | 1 | 0 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
|  | 71 | 15 | 8 | 2 | 33 | 23 | 6 | 0 | 0 | 3 | 0 | 0 | 1 | 0 | 1 | 1 | 0 | 0 | 0 |
|  | 72 | 8 | 1 | ? | 28 | 12 | 2 | 1 | 0 | 10 | 1 | 0 | 2 | 0 | 2 | 1 | 1 | 0 | 0 |
|  | 73 | 18 | 7 | 4 | 29 | 13 | 2 | 8 | 0 | 10 | 0 | 0 | 3 | 1 | 1 | 2 | 1 | 0 | 0 |
|  | 74 | 8 | 3 | 2 | 41 | 14 | 2 | 3 | 0 | 17 | 0 | 0 | 2 | 0 | 2 | 2 | 1 | 2 | 0 |
| 185 NORTH CENTRAL OKLAHOMA |  | ( 1) |  |  |  |  |  | ( 1 * 0) |  |  |  |  | ( 0) |  |  | ( 0) |  | ( 0) |  |
|  | 70 | 0 | 0 | 0 | 3 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
|  | 71 | 1 | ? | 0 | 6 | 1 | 0 | 0 | 0 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
|  | 72 | 1 | 0 | 0 | 4 | 1 | 0 | 0 | 0 | 2 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
|  | 73 | 2 | 1 | 0 | 5 | 0 | 0 | 0 | 0 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
|  | 74 | 0 | ? | ? | 5 | 1 | 0 | 0 | 0 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 186 NORTHEASTERN OKLAHOMA |  | ( 4) |  |  |  |  |  | ( 1 * 0) |  |  |  |  | ( 0) |  |  | ( 2) |  | ( 0) |  |
|  | 70 | 8 | 7 | 4 | 17 | 10 | 7 | 0 | 0 | 2 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
|  | 71 | 12 | 8 | 5 | 21 | 14 | 4 | 1 | 0 | 3 | 0 | 0 | 1 | 0 | 0 | 0 | 0 | 0 | 0 |
|  | 72 | 13 | 7 | 1 | 25 | 11 | 2 | 3 | 0 | 6 | 0 | 0 | 1 | 0 | 0 | 1 | 0 | 0 | 0 |
|  | 73 | 16 | 6 | 2 | 26 | 10 | 1 | 2 | 0 | 7 | 1 | 0 | 1 | 0 | 1 | 1 | 1 | 0 | 0 |
|  | 74 | 8 | 2 | ? | 34 | 8 | 1 | 2 | 0 | 11 | 0 | 0 | 3 | 0 | 2 | 1 | 0 | 1 | 0 |
| 187 NORTHWESTERN OKLAHOMA |  | ( 1) |  |  |  |  |  | ( 1 * 0) |  |  |  |  | ( 0) |  |  | ( 0) |  | ( 0) |  |
|  | 70 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
|  | 71 | 0 | 0 | 0 | 3 | 1 | 0 | 0 | 0 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
|  | 72 | 1 | ? | 0 | 5 | 3 | 0 | 1 | 0 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
|  | 73 | 2 | 2 | 1 | 6 | 3 | 1 | 0 | 0 | 2 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
|  | 74 | 0 | ? | ? | 6 | 2 | 1 | 0 | 0 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 188 SOUTHEASTERN OKLAHOMA |  | ( 1) |  |  |  |  |  | ( 1 * 0) |  |  |  |  | ( 0) |  |  | ( 0) |  | ( 0) |  |
|  | 70 | 2 | 2 | ? | 12 | 6 | 2 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
|  | 71 | 4 | 1 | 1 | 14 | 6 | 3 | 0 | 0 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
|  | 72 | 3 | 1 | 0 | 12 | 0 | 0 | 1 | 0 | 2 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
|  | 73 | 4 | 2 | 0 | 13 | 3 | 1 | 1 | 0 | 2 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
|  | 74 | 4 | 1 | 0 | 13 | 0 | 0 | 1 | 0 | 3 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 189 SOUTHWESTERN OKLAHOMA |  | ( 1) |  |  |  |  |  | ( 1 * 0) |  |  |  |  | ( 0) |  |  | ( 0) |  | ( 0) |  |
|  | 70 | 0 | ? | ? | 6 | 5 | 4 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
|  | 71 | 2 | 1 | 1 | 10 | 6 | 2 | 0 | 0 | 2 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
|  | 72 | 5 | 4 | 1 | 12 | 7 | 3 | 3 | 0 | 3 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
|  | 73 | 7 | 5 | 1 | 12 | 4 | 1 | 1 | 0 | 3 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
|  | 74 | 5 | 2 | ? | 11 | 3 | 0 | 1 | 0 | 3 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

(1) NUMBER OF STATIONS REPORTING A FULL YEAR'S VALID DATA
(2) NUMBER OF STATIONS REPORTING AT LEAST 3 24-HR VALUES OR 400 HOURLY VALUES
? STATIONS WITH INCOMPLETE DATA MAY BE EXCEEDING THE ANNUAL STANDARD; SEE APPENDICES
* CO STANDARDS ARE IN MILLIGRAMS PER CUBIC METER

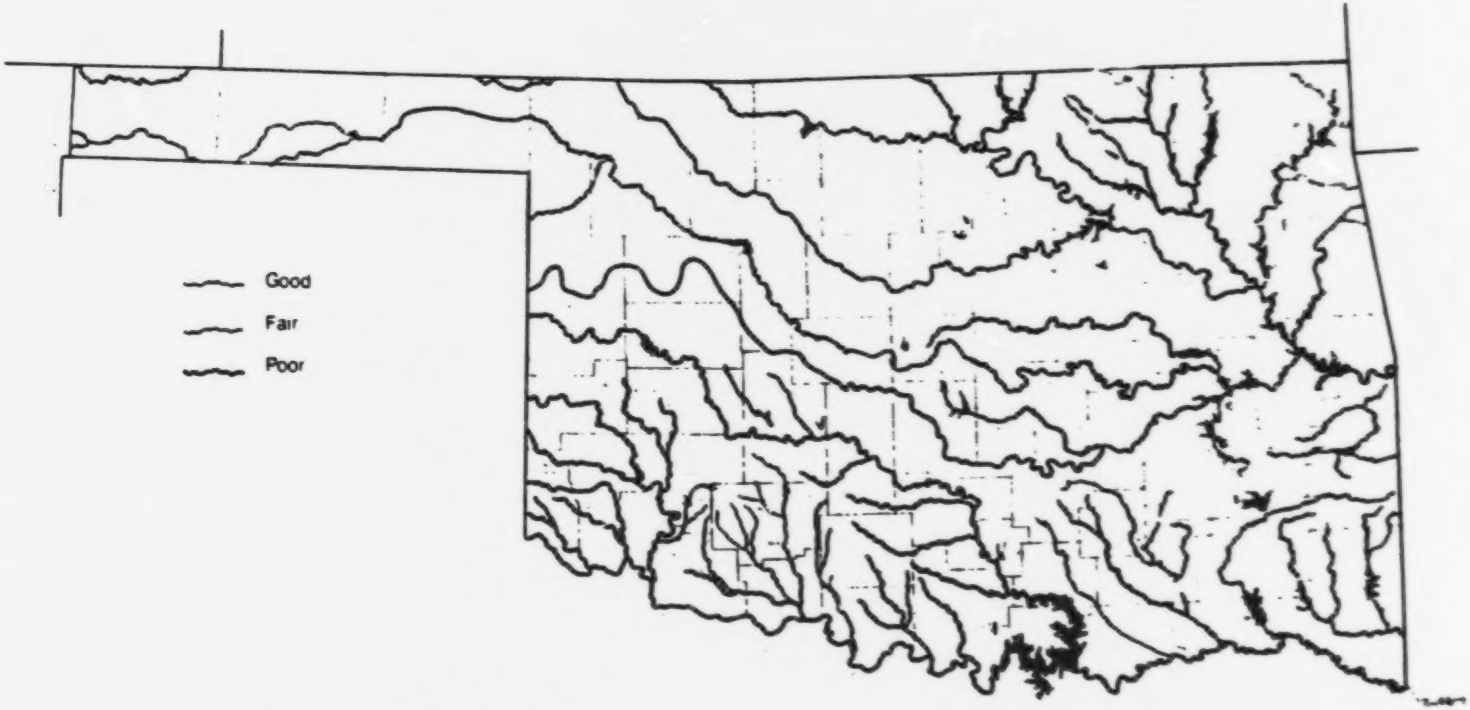


Figure J-60. Discharge-weighted average of concentrations of total dissolved solids in streams and existing lakes. (Oklahoma Water Resources Board, Oklahoma Comprehensive Water Plan, Sept. 1975, Figure 11-6, Resource chapter - p.5.)

Note: A color copy of this diagram is available for viewing at the FEA Freedom of Information Office in Washington, D.C.

River. Inflow from tributaries below Lake Texoma reduces the dissolved solids content of the Red River near the Arkansas-Oklahoma line to about one-fifth the average value near the Texas-Oklahoma line.

Water has migrated through salt deposits emerging as salt seeps and springs that have naturally polluted several streams. These include the Arkansas, Cimarron and Salt Fork of the Arkansas in northwestern Oklahoma and the Red River and its tributaries, the North Fork, Salt Fork, Elm Fork, and Prairie Dog Town Fork in southwestern Oklahoma. The Canadian and Washita Rivers in west central Oklahoma have this natural pollution, but it is of the sulfate type coming from gypsum deposits instead of salt deposits.

Brine releases from oil and gas production have contributed to the pollution of many streams and groundwater supplies. The waters of Walnut Bayou and Mud Creek (in the south central portion of the state), the Canadian River above Eufaula Reservoir, the Arkansas, Verdigris, and Caney Rivers are high in chloride content resulting from improper disposal of oilfield brines in the early days of the oil industry. Variable amounts of salt water are produced per barrel of oil, depending on the age of the oil field. In new fields, little or no brine is produced, but older, nearly depleted fields may yield as much as 100 barrels of salt water per barrel of oil produced. Oklahoma state water pollution control agencies report over 95 percent of the brine produced from petroleum activities is being reinjected into production strata for pollution control and secondary recovery.

Water pollutants associated with agricultural and ranching operations are fertilizers, herbicides, insecticides, salt concentrations in irrigation return flows, animal wastes, and silt from overland runoff. Excessive concentrations of these pollutants can and do change the quality of streams during periods of high runoff and ground water during seepage. Mining wastes and thermal pollution also contribute to the pollution of streams and ground water in Oklahoma.

## Groundwater Quality

The water quality of groundwater resources in Oklahoma is generally good, though some water quality problems do exist. The Dog Creek Shale and Blaine Gypsum are high in sulfates and exceed water quality standards (i.e., < 250 mg/l). The water is of sufficient quality for irrigation, however. Brine infiltration presents a major problem in the Vamoosa Formation. Abandoned, improperly plugged oil and gas wells are a source of contamination. Possible contamination also exists from wells used by the petroleum industry for brine disposal and by other industries for chemical waste disposal.

# APPENDIX K

## ATMOSPHERIC HEALTH EFFECTS OF POLLUTANTS RELEASED FROM PETROLEUM PRODUCTION

# APPENDIX K

## ATMOSPHERIC HEALTH EFFECTS OF POLLUTANTS RELEASED FROM PETROLEUM PRODUCTION

This appendix is provided to indicate the general nature of possible health effects resulting from exposure to sulfur oxides, carbon monoxide, and hydrocarbons, the major atmospheric pollutants associated with petroleum production. It is certainly impractical and effectively impossible to make estimates of the actual health consequences of the alternative pricing strategies examined. The information contained in the appendix is provided as background in considering the impact of the example cases described in the main body of the text.

### A. Health Impacts of Sulfur Oxides

In assessing the health impacts associated with sulfur oxides it is important to realize that the most significant impact is not produced by sulfur dioxide itself. Sulfur dioxide has little effect on the respiratory system if administered by itself. It is easily absorbed by the fluid in the upper respiratory tract tissues and is relatively non-irritating. The health impacts associated with atmospheric sulfur oxides are due almost exclusively to sulfuric acid aerosols and particulate sulfates.

The sulfur dioxide emitted by boilers can be oxidized in the atmosphere to produce sulfur trioxide gas ($SO_3$) and this in turn can be hydrolyzed in moist atmospheres to yield sulfuric acid, $H_2SO_4$. The sulfuric acid can react with available bases to produce particulate sulfates:

$$SO_2 \xrightarrow[\text{catalyst}]{\text{oxidant}} SO_3 \xrightarrow{H_2O} H_2SO_4 \rightarrow \text{sulfates}$$

Thus the health effects associated with sulfur oxides will be increased by any substances which tend to accelerate the conversion of sulfur dioxide into sulfuric acid and particulate sulfates. Fine particulates are known to catalyze the oxidation of sulfur dioxide, as are particulate trace metals such as manganese, vanadium, and iron. Particulate trace metals have been shown to result in a threefold to fourfold increase in the irritant response of guinea pigs to sulfur dioxide. In addition, these trace metals can react with sulfuric acid aerosols to produce highly toxic metallic sulfates. Zinc ammonium sulfate, for example, is known to be twice as toxicologically potent as sulfuric acid.[1] Oxidants such as ozone will also provide the potential for the adverse effects of sulfur oxides by promoting the oxidation of sulfur dioxide.

One important effect which has been shown to be associated with atmospheric sulfur oxides is respiratory irritation. According to EPA's Air Quality Criteria for Sulfur Oxides:[2]

> Laboratory observations of respiratory irritations suggest that most individuals will show a response to sulfur dioxide at concentrations of 5 ppm (~14 mg/m$^3$) and above. At concentrations of 1 ppm to 2 ppm (~3 mg/m$^3$ to ~6 mg/m$^3$) an effect can be detected only in certain sensitive individuals, and on occasion, exposures to 5 ppm to 10 ppm (~14 mg/m$^3$ to ~30 mg/m$^3$) have been shown to cause severe bronchospasm in such persons; no further special study at lower concentrations has been carried out with these individuals. The exposure of the more sensitive individuals to 1 ppm (~3 mg/m$^3$), although it does not produce severe bronchospasm, does elicit a detectable response.
>
> Sulfuric acid is a much more potent irritant to man than is sulfur dioxide, and its effects are highly dependent on particle size. Insufficient data are available for quantitative assessment of the health hazard. There is inadequate information on the response of human subjects to any of the other particulate sulfates.

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[1] Environmental Research and Technology, Inc., Sources and Impacts of Sulfates in the Atmosphere (working draft), EPA P-1291, Section 6.1.

[2] U.S. Department of Health, Education and Welfare, Public Health Service, National Air Pollution Control Administration, Air Quality Criteria for Sulfur Oxides, NAPCA Publication No. AP-50, January 1969, p. 100.

Sulfuric acid generally has a more pronounced effect than sulfur dioxide. Amdur et al.[3] studied the effects of exposure to sulfuric acid aerosols of mass mean diameters (MMD) of 1 micron for a 15-minute period. In 15 subjects exposed to concentrations ranging from 0.35 mg/m$^3$ to 0.5 mg/m$^3$ the following effects were observed: increased respiration rate (30 percent), decreased respiratory flow rate (20 percent), and decreased tidal volume (28 percent). These changes generally occurred within the first 3 minutes of exposure and were reversible upon termination of exposure. In interpreting these results it should be kept in mind that 1 mg of sulfur dioxide, if completely oxidized and hydrolyzed, will generate about 1.53 mg of pure sulfuric acid, or proportionately larger mass of more dilute sulfuric acid solutions.

Sulfuric oxides have been implicated in a number of physiological effects other than respiratory irritation. The thresholds for some of the more important of these effects are displayed in Table K-1. Threshold concentrations are shown for sulfur dioxide, sulfuric acid, and various combinations of the two.

In addition to acute effects produced by relatively high concentrations, long-range effects of low level occupational exposure may also be observed. Most of the available data on chronic long-range effects of sulfur dioxide exposure come out of epidemiological studies in which various public health statistics are regressed against sulfur dioxide concentration data in order to demonstrate correlations between the two variables. Data on demographic variables such as age distribution also have to be taken into account in such analyses to filter out effects which may be due to varying disease incidence rates among different age groups.

A number of cautions have to be emphasized in the interpretation of multiple regression analyses of epidemiological data.[4]

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[3] M.O. Amdur et al., "Innalation of Sulfuric Acid Mist by Human Subjects, "American Medical Association Archives Inc. Hyg. Occup. Med. 6 (1952): 306-313.

[4] Energy Resources Co. Inc., A Conceptual Framework for Analyzing Alternative Nondegradation Proposals, for the U.S. Environmental Protection Agency, Policy Planning Division, November 3, 1975.

## TABLE K-1

## THRESHOLD CONCENTRATIONS OF SULFUR DIOXIDE, SULFURIC ACID, AND THEIR COMBINATIONS FOR VARIOUS RESPONSES

| PROCEDURE USED | THRESHOLD CONCENTRATION | | | |
|---|---|---|---|---|
| | $H_2SO_4$ | $SO_2$ | $H_2SO_4$ + | $SO_2$ |
| | $\mu g/m^3$ | $\mu g/m^3$ | $\mu g/m^3$ | $\mu g/m^3$ |
| Threshold Concentration of Irritation Effects & Odor Perception | 600-850 | 1,600-2,600 | >300 | 500 |
| Data Obtained by the Method of Eye Adaption to Darkness | 630-730 | 920 | >300 | 500 |
| Data Obtained by the Method of Optical Chronaxie | 730 | 1,500 | 600 | 1,200 |
| Encephalographic Method | 630 | 900 | >300 | 500 |
| "Electrocortical" Conditioned Reflex | 400 | 600 | 150<br>300 | 500<br>250 |

Source: U.S. Environmental Protection Agency, Air Quality Criteria for Sulfur Oxides, p. 99.

Correlations do not establish causal relationships. Moreover, even with a highly significant correlation the correlation coefficients cannot be taken very seriously. There are too many possibilities of interrelationships among the variables and of significant factors not taken into account. In this case, the variables overlooked may include factors of occupation, socioeconomic position, or habit. Additional problems stem from the nature of the data. Measurements of exposure to pollution are made inaccurate by population mobility, different activities, and local variations in pollutant levels. Examining mortalities during days of varying pollution levels is problematic because it does not indicate a relationship between the origins of diseases and air quality. Even when high mortalities are observed over periods of high pollution levels, these may just indicate an advancement by a few weeks of the time of death. After examining annual respiratory disease mortality rates in high versus low pollution areas, it is impossible to take into account all the distinctions between urban and rural areas which might also affect death rates. Similar difficulties arise with studies of morbidity data. Employee absence rates correlate with pollution levels, but both of these are also high on certain days of the week. Much of the collection of data is either by questionnaire, where recall may be a problem, or else by studying historical statistics such as census reports and comparing them with whatever air pollution data are available, which may not be accurate for the time period in question. Finally, negative results are not published, so the positive ones may be given too much weight.

Despite these problems, much useful work has been done with correlations. Lave has been extremely thorough, examining a variety of variables and several possible algebraic forms. Together with Freeburg, he reports a best-fit linear model:[5]

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[5] L.B. Lave and L.C. Freeburg, "General Safety Considerations," Nuclear Safety 14(5): 417.

$$MR = 19.61 + .041P + .071Smin + .001D + .041NW + .69E + e,$$

where MR = Mortality rate per 10,000 population
P = Particulate concentration (annual mean)
Smin = Minimum biweekly sulfur concentration (as $SO_4$)
D = Population density
NW = Percent of population which is non-white
E = Elderly over 65
e = Error

This was the result of a regression of 1960 data from 117 U.S. cities; 82.7 percent of the variance is explained.[6] The fact that Lave and Freeburg use sulfate measurements for sulfur levels may be helpful, since sulfate is now recognized as the more deleterious substance. On the basis of this equation, a 10 percent increase in $SO_4$ and in particulate concentration would mean a .9 percent increase in the total mortality rate. A 1969 regression with data from 89 cities indicates that a 1 $\mu g/m^3$ increase in mean particulate or mean $SO_2$ levels would result in increases in mortality rates of .085 per 10,000 people per year or .039 per 10,000 people per year, respectively.

A summary of some of the important health and vegetation effects of sulfur oxides is presented in Figures K-1 and K-2.

## B. Health Impacts of Atmospheric CO

Carbon monoxide owes many of its toxic properties to the fact that it competes with oxygen for binding sites on the hemoglobin molecules. Since the affinity of carbon monoxide for hemoglobin is about 200 times as great as that of oxygen, even relatively small concentrations may significantly impair oxygen transport. CO binds with hemoglobin to form carboxyhemoglobin, COHb. Equilibrium levels of COHb can be related to ambient CO concentrations by the following empirical relationship:[7]

$$\text{COHb in \%} = 0.16 \text{ (CO in ppm)} + 0.5,$$

where 0.5 is the estimated background level of COHb, resulting from the existence of natural endogenous CO sources in the body.

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[7] J.R. Goldsmith and S.A. Landaw, "Carbon Monoxide and Human Health," Science 162 (1968): 1352-1359.

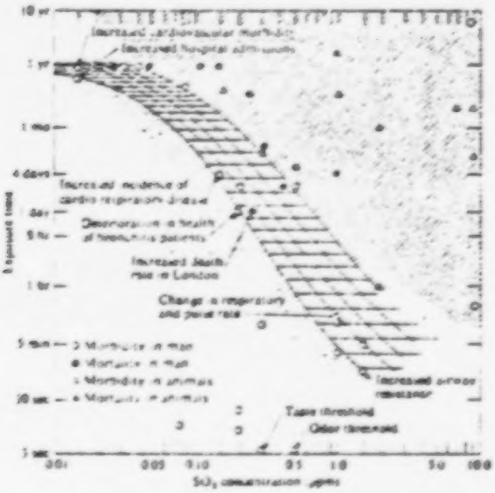

Figure K-1. Effects of sulfur oxides pollution on health. Shaded area represents range of concentrations and exposure times in which deaths have been reported in excess of normal expectation. Grid area represents range of concentrations and exposure times in which significant health effects have been reported. Speckled area represents ranges of concentrations and exposure times in which health effects are suspected. (S.J. Williamson, *Fundamentals of Air Pollution*, Reading, Mass.: Addison-Wesley Publishing Co., 1973, Figure 8.2, p. 263, from USDHEW, PHS, *Air Quality Criteria for Sulfur Oxides*, NCAC, 1967.)

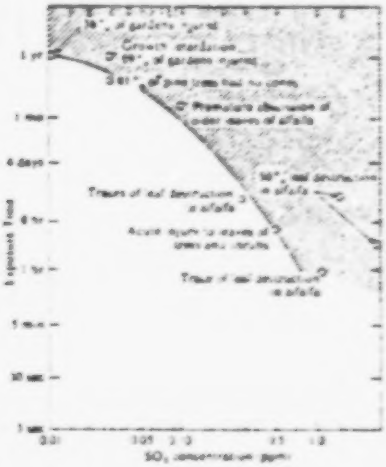

Figure K-2. Effects of sulfur on vegetation. Shaded area represents the range of concentrations and exposure times in which injury to vegetation has been reported; white area, the range of concentrations and exposure times of undetermined significance to vegetation. (Williamson, *Fundamentals of Air Pollution*, Figure 8.3, p. 263, from USDHEW, PHS, *Air Quality Criteria for Sulfur Oxides*, NCAC, 1967.)

This relationship between CO concentrations and COHb levels is useful since toxic effects data are frequently reported in terms of COHb levels rather than directly in terms of ambient CO.

A number of psychological effects (impaired performance on various sensory discrimination and psychomotor tests) have been noted in conjunction with this level of COHb. Figure K-3 summarizes the results of a study performed by Shulte on the effects of various COHb levels on a number of psychological functions. Statistically significant performance impairments are observed to be associated with CO exposure and elevated COHb levels. The effect observed at 8.5 percent, though relatively small, is significant.

Beard and Wertheim[8] reported impaired temporal discrimination associated with CO exposure. Eighteen subjects were exposed to pairs of 1,000 Hz audio signals of varying lengths in a soundproof room, and asked to report which persisted longest. The first tone in each pair lasted for 1 second, and the next lasted for between 0.675 and 1.325 seconds. The results of the experiment are shown in Figure K-4. Significant impairment was observed at a CO concentration of 58 $\mu g/m^3$; the effect was observed in 90 minutes.

McFarland et al.[9] studied the effect of CO exposure on visual discrimination. His experiments measured the intensity of the weakest red light which could be perceived by subjects in 0.1 second flashes against an illuminated background. The relationship between COHb levels and visual thresholds is shown in Figure K-6. A significant effect is observed at 5 percent.

Another study reported the effect of CO exposure on ability to estimate time intervals: "While individually isolated in a noise-insulated exposure chamber, seven subjects estimated the passage of 10 and 30 second intervals. Estimation of 10 second intervals was not affected by CO exposure. A highly significant dose-related performance decrement occurred, however, with attempts to estimate

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[8] R.R. Beard and G.A. Wertheim, "Behavioral Impairment Associated with Small Doses of Carbon Monoxide," American Journal of Public Health 57 (1967): 2011-2012.

[9] R.A. McFarland et al., "The Effects of Carbon Monoxide and Altitude on Visual Thresholds," Aviation Medicine 14 (1944): 381-394.

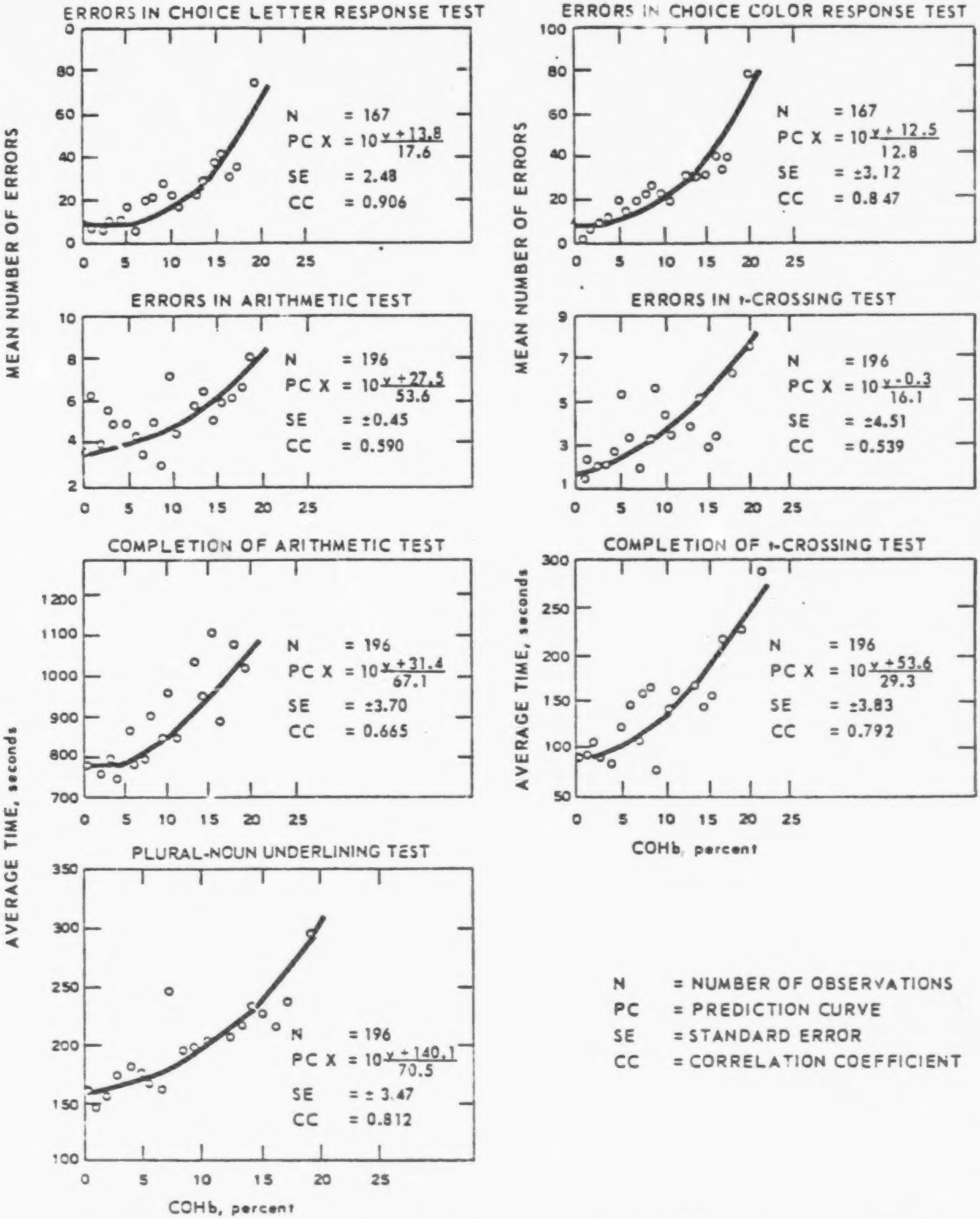

Figure K-3. Effects of small concentrations of COHb on certain psychomotor tests. (J.H. Schulte, "Effects of Mild Carbon Monoxide Intoxication," Archives of Environmental Health (7) (1963), Figure 8-7, pp. 8-16.)

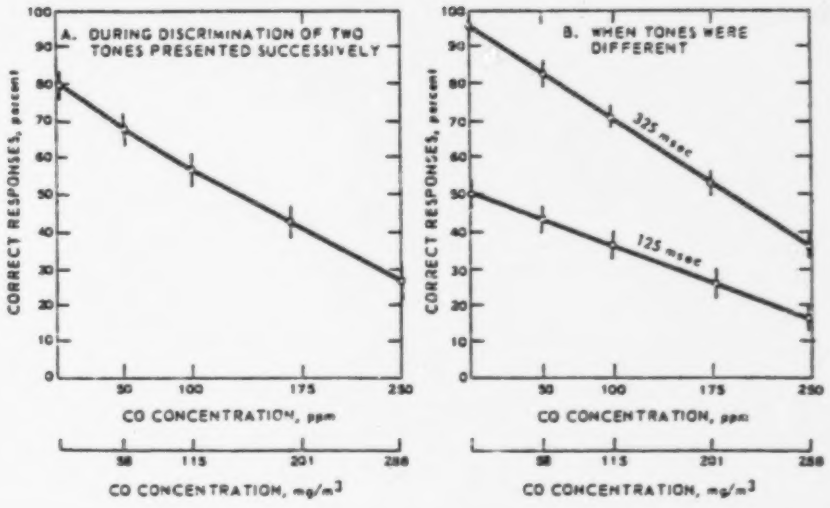

Figure K-4. Mean percent correct responses (± one standard deviation) to 1,000-hertz tone by 18 human subjects during exposure to CO.

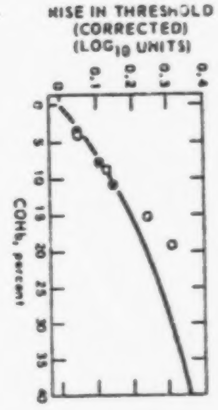

Figure K-5. Time after initial exposure to each concentration of CO that means correct response fell two standard deviations from mean performance level in absence of CO.

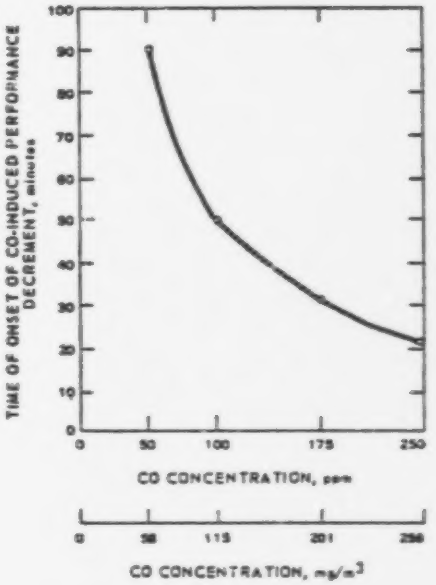

Figure K-6. Relation between COHb and visual threshold.

Source: R.R. Beard and G.A. Wertheim, "Behavioral Impairment associated with Small Doses of Carbon Monoxide," American Journal of Public Health (57) (1967).

30 second intervals. Exposures of 64 minutes at 58 $\mu g/m^3$ produced significant impairment."[10]

Some data on the effects of CO concentrations of 58 $\mu g/m^3$ on visual performance are presented below:[11]

- Relative brightness threshold after 49 minutes showed 4.4 percent impairment.
- Critical flicker fusion frequency after 50 minutes showed 5.0 percent impairment.
- Visual acuity after 27 minutes showed 5.5 percent impairment.
- Visual acuity after 60 minutes showed 17.5 percent impairment.

Continued exposure to low levels of carbon monoxide has been reported to be associated with a chronic condition known as the CO syndrome, although according to EPA's Air Quality Criteria for Carbon Monoxide, "the evidence for the occurrence of such a condition is inadequate and based primarily on subjective symptoms." The criteria document also notes that some epidemiological evidence exists supporting chronic effects of low level exposure to CO:[12]

> The evidence to date, although inconclusive, suggests that weekly average CO values in excess of from 9 to 16 $mg/m^3$ may be associated with an increase in mortality in hospitalized patients with myocardial infarction. Substantiation of this impression will require a study of the prognosis of myocardial infarction patients in relationship to COHb levels measured at admission to the hospital.

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[10] U.S. Department of Health, Education and Welfare, Public Health Service, National Air Pollution Control Administration, Air Quality Criteria for Carbon Monoxide, National Air Pollution Control Administration Publication No. AP-62, March 1970, pp. 8-21.

[11] U.S. Department of Health, Education and Welfare, Air Quality Criteria for Carbon Monoxide, 1970, pp. 8-22.

[12] U.S. Department of Health, Education and Welfare, Air Quality Criteria for Carbon Monoxide, 1970, pp. 9-18.

Although most of the data deal with the effects of CO exposure on healthy individuals, some work has been done on more sensitive elements of the population. Among the groups who could be expected to be most sensitive to the toxic effects of CO are:

1. People with anemia.
2. People with cardiovascular disease resulting in circulation impairment.
3. People with increased oxygen demand due to abnormal metabolic states.
4. People with chronic pulmonary disease.
5. The developing fetus.

In addition, cigarette smokers may constitute a sensitive population group since they are already exposed to high levels of CO in cigarette smoke.

## C. Health Impacts of Atmospheric Hydrocarbons

The assessment of the health impacts associated with ambient atmospheric hydrocarbons is more difficult than the equivalent assessment of carbon monoxide, chiefly because of the ill-defined nature of hydrocarbon residuals. The substances which are measured as "hydrocarbons" by conventional monitoring techniques (e.g., flame ionization methods) in fact consist of hundreds of chemically distinct substances in many chemical categories: aliphatics, aromatics, alicyclic compounds, heterocyclic compounds, organometal compounds, etc. Each of the individual components has its own toxic properties, and synergistic and antagonistic interactions complicate the analysis of the toxicity of the mixture. Although no information has been located on the specific hydrocarbon components of process effluents from in-situ combustion, some data are available on the proportions of various hydrocarbons in total atmospheric hydrocarbons from a variety of pollution sources. According to EPA's Air Quality Criteria for Hydrocarbons:

> In a series of 200 samples taken in one urban location, average concentrations of the most abundant hydrocarbons were as follows (in ppm as carbon): methane, 3.22; toluene, 0.37; n-butane, 0.26; i-pentane, 0.21; ethane, 0.20; benzene, 0.19; n-pentane, 0.18; propane, 0.15; and ethylene, 0.12. Among classes of hydrocarbons,

> the alkanes predominate, even if methane is excluded. They are followed by the aromatics, olefins, acetylenes, and alicyclics.

Although these proportions may be broadly representative of those found in combustion residuals (since a large proportion of urban air pollution is derived from fossil fuel combustion products), it would be foolhardy to assume that these ratios could be extrapolated quantitatively to those found in in-situ combustion residuals.

The analysis of hydrocarbon impacts is further complicated by the fact that they are subject to chemical transformations (particularly oxidation through reactions with ozone and other oxidants) which can substantially alter their toxicity. Partially oxidized hydrocarbons contain highly irritating and toxic aldehydes and ketones, and as photochemical smog, can cause significant air quality problems. Thus, the impact of atmospheric hydrocarbons will depend to a significant extent on associated oxidant levels.

The following general comments can be made about the toxicity of the various hydrocarbon pollutants which might be found in or produced from in-situ combustion emissions.[13]

> The aliphatic and alicyclic hydrocarbons are generally biochemically inert, though not biologically inert, and are only reactive at concentrations of $10^2$ to $10^3$ higher than those levels found in the ambient atmosphere. No effects have been reported at levels below 500 ppm. The aromatic hydrocarbons are biochemically and biologically active. The vapors are more irritating to the mucous membranes than equivalent concentrations of the aliphatic or alicyclic groups. Systematic injury can result from the inhalation of vapors of the aromatic compounds; no effects, however, have been reported at levels below 25 ppm.
>
> Pulmonary function and eye irritation have been evaluated by the exposure of experimental animals and humans to various mixed atmospheres that had the characteristic of providing the milieu necessary for hydrocarbon reactivity. Experimental data indicate that the precursors of the eye irritants are

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[13] U.S. Department of Health, Education and Welfare, Air Quality Criteria for Hydrocarbons, National Air Pollution Control Administration Publication No. AP-64, March, 1970, pp. 8-30.

hydrocarbons (as well as other organic compounds) in combination with oxides of nitrogen; the alkylbenzenes and olefins are more effective precursors than paraffins, benzene, and acetylenes. The products of photochemical reactions that have been identified as effective eye irritants are formaldehyde, acrolein, peroxyacyl nitrates, and peroxybenzoyl nitrate. In general, the most characteristic and important effect of aldehydes for both humans and animals is primary irritation of the eyes, upper respiratory tract, and skin. The unsaturated aldehydes are several times more toxic than the corresponding aliphatic aldehydes, and toxicity generally decreases with increasing molecular weight within the unsaturated and aliphatic aldehyde series. Animal experiments have shown that aldehydes can affect respiratory functions, causing such effects as an increase in flow resistance and tidal volume and a decrease in the respiratory rate. Animal populations, although many of the effects attributed to photochemical smog, are indirectly related to ambient levels of these hydrocarbons.

# APPENDIX L

## CHEMICALS OF POTENTIAL USE IN SURFACTANT/POLYMER FLOODING

## TABLE L-1

## CHEMICALS PROPOSED FOR USE AS SURFACTANTS

---

Ditetradecyl dimethyl ammonium chloride
Dodecyl trimethyl ammonium chloride
Hexadecyl trimethyl ammonium chloride
Alkyl phenoxypolyethoxy ethanol
p-Chloroaniline sulfate laurate[1]
p-Toluidene sulfate laurate
Polyglycerol monolaurate
Glycerol disulfoacetate monomyristate
n-Methyltaurine oleamide
Monobutylphenyl phenol sodium sulfate
Polyoxyethelene alkyl phenol
Morpholine stearate
Pentaerythritol monostearate
Dihexyl sodium succinate
Diethyleneglycol sulfate
Sodium sulfate oleylethydanilide
Alfa olefin sulfonate
Alkyl aryl sulfonate
Alkyl aryl naphthenic sulfonate with monovalent cation
Hexadecylnaphthalene sulfonate
Sodium lauryl sulfonate
Triethanolamine laurate
Triethanolamine myristate
Triethanolamine oleate
n-Dodecyl-diethleneglycol sulfate
Sodium glyceryl monolaurate sulfate

---

[1] Halogenated compounds, though proposed in the literature, are unlikely to be used in field operations because their possible presence in produced oil streams would poison the catalysts at the refinery.

Source: Energy Resources, Tertiary Oil Recovery, 1976, p. 97.

## TABLE L-2

## MATERIALS PROPOSED FOR USE AS MOBILITY BUFFERS

---

- Aldoses
  - B series
  - L series
- Amines
- Carboxymethylcellulose
- Carboxyvinyl polymer
- Dextrans
- Desoxyribonucleic acid
- Glycerin
- Ketoses
  - B series
  - L series
- Polyacrylamide*
- Polyethylene oxide*
- Polyisobutylene in benzene
- Rubber in benzene
- Saccharides
  - Conjugated saccharides
  - Disaccharides
  - Monosaccharides
  - Polysaccharides*
- Tetrasaccharides

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*Most commonly used.

Source: Energy Resources, *Tertiary Oil Recovery*, 1976, p. 98.

## TABLE L-3

## HYDROCARBONS USED AS FRACTION OF MICELLAR SLUG
(Or in Miscible Displacement Processes)

- Alkylated aryl compounds
- Anthenic compounds
- Aryl compounds with mono cyclic compounds
    - Alkyl phenols
    - Benzene
    - Toluene
- Aryl compounds with polycyclic compounds
- Crude oil*
- Partially refined fractions of crude oil
    - Overheads from crude columns
    - Side cuts from crude columns
    - Gas oils
    - Straight run gasoline
    - Kerosine
    - Liquefied petroleum gas
    - Naphthas
    - Heavy naphthas
- Refined fraction of crude oil
    - Paraffinic compounds
        - Decane
        - Dodecane
        - Heptane
        - Octane
        - Pentane
        - Propane
        - Cycloparaffinic compounds
        - Cyclohexane
- Naphthenic compounds

---

*Most commonly used

Source: Energy Resources, Tertiary Oil Recovery, 1976, p. 99.

## TABLE L-4

## CHEMICALS PROPOSED FOR USE AS ELECTROLYTES

---

- Acids
  - Hydrochloric acid
  - Inorganic acids
  - Organic acids
  - Sulfuric acid

- Bases
  - Inorganic bases
  - Organic bases
  - Sodium hydroxide

- Salts
  - Inorganic salts
  - Organic slats

- Sodium hydroxide

- Sodium nitrate

- Sodium sulfate

---

Source: Energy Resources, Tertiary Oil Recovery, 1976, p. 100.

## TABLE L-5

## CHEMICALS PROPOSED FOR USE TO BLOCK EXCHANGE SITES IN THE FORMATION

(Preflushing)

---

Quarternary ammonium salts

Fluoride solutions

Potassium permanganate

Sodium hydroxide

---

Source: Energy Resources, Tertiary Oil Recovery, 1976, p. 101.

## TABLE L-6

## CHEMICALS PROPOSED FOR USE AS COSURFACTANTS

---

- Alcoholic liquors
  - Fusel oil
- Alcohols
  - Alkaryl alcohols
    - Phenol
    - p-Nonyl phenol
- Amyl alcohols
  - Isopentanol*
  - 2-pentanol*
- Cresol
- Decyl alcohols
- Ethanol
- Isobutanol
- n-Butanol
- Cyclohexanol
- 1-Hexanol*
- 2-Hexanol*
- 1-Octanol
- 2-Octanol
- Isopropanol*
- Aldehydes
  - Formaldehyde
  - Gluteraldehyde
  - Paraformaldehyde
- Amides
- Amino compounds
- Esters
  - Sorbitan fatty ester
- Ketones

---

Source: Energy Resources, Tertiary Oil Recovery, 1976, p. 102.

# APPENDIX M

## AIR QUALITY REGULATORY RESTRICTIONS

The United States Environmental Protection Agency interpreted the preconstruction review requirements of the Clean Air Act on December 21, 1976. At that time the restrictions in the national air quality standards for the growth of new or expanded stationary air pollution sources were established. 1/ The ruling stated that a major new source may locate in an area with air quality exceeding the national standard (nonattainment area) only if stringent conditions can be met. These conditions include: (a) the greatest possible degree of control for the new source's emissions; (b) an equivalent emission reduction (emission offset) by existing sources within the area; and (c) that progress will be made toward achievement of the standards in the nonattainment areas. Tentatively, the EPA has defined a major source as any structure, building, facility, installation or operation (or combination thereof) for which the allowable emission rate is 100 or more tons per year per criteria pollutant (1,000 tons/year or carbon monoxide). Specifically related to area sources or multiple point sources (under which tertiary oil recovery would be categorized) the regulation states that for a group of proposed sources, which do not individually meet the stated source requirements (e.g., individual tertiary wells located in a producing oil field) the group of sources should be collectively reviewed as a major source.

In areas where current oil fields coincide with nonattainment areas (see the state maps in Appendix I), the air quality regulatory restrictions may inhibit the future size and scope of operation for tertiary oil recovery fields.

As indicated on the individual state maps of oil fields and AQMA's, there are areas in California, Texas, Wyoming, Louisiana and Oklahoma, where future tertiary oil field development may be inhibited in AQMA's. These AQMA's would be subject either to the previously mentioned nonattainment major source regulations or the U.S. Environmental Protection Agency's Significant Deterioration Regulations which are currently under study for approval by the Congress of the United States. In order for large scale tertiary recovery methods to occur in these areas, a site specific air quality impact study would be needed.

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1/ Federal Register, Vol. 41, No. 246, December 21, 1976

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# GLOSSARY

# GLOSSARY

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| acute | Describing a toxic effect having a rapid onset and generally extreme symptoms. (See CHRONIC) |
| additive | Describing an interaction between two toxic chemicals in which the combined effect is equal to the sum of the effects produced if the two chemicals are administered separately. (See SYNERGISTIC) |
| adsorption | The accumulation of gas or liquid molecules on the surface of a solid particle. |
| aliphatic | Describing organic compounds which are not aromatic (q.v.). |
| ambient | Pertaining to the general environment; e.g., the ambient concentration of a particular pollutant. |
| antagonistic | Describing an interaction in which two toxic substances, when administered together, produce a combined effect which is less in magnitude than the sum of the effects which would be produced by the separate administration of each of the chemicals. (See SYNERGISTIC and ADDITIVE) |
| application factor | An empirical factor used for predicting a "safe level" of a particular chemical on the basis of its 96 hr LC50 (q.v.). For example, the EPA Water Quality Criteria set safe levels for many pollutants at concentrations equal to .01 times their 96 hr LC50; this factor of .01 is known as an application factor. |
| aquifer | A water-bearing layer of permeable rock, sand, or gravel. |
| AQCR | Air Quality Control Region. |
| AQMA | Air Quality Maintenance Area. |
| arithmetic mean | The average of a set of measurements; equal to the sum of the measurements divided by the number of measurements. |
| aromatic hydrocarbons | A group of generally highly toxic hydrocarbons, characterized by a chemical structure related to that of one or more benzene rings. |

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| artificial lift wells | Wells in which the natural pressure in the reservoir must be supplemented by the use of pumps or other lift methods. |
| bactericides | Chemicals which are toxic to bacteria; frequently added to injected fluids to control the growth of bacterial slimes in injection wells. |
| barrel | A standard volume measure equal to 42 U.S. gallons. |
| BATEA | Best Available Technology Economically Achievable; describes an effluent treatment standard which must be set for all industries discharging pollutants into U.S. waters by 1983. The standards are set by the Effluent Guidelines Division of the U.S. Environmental Protection Agency under the authority of Public Law 92-500. |
| bbl | Abbreviation for barrel (q.v.). |
| benthic | Describing organisms living on the bottoms of water bodies. |
| bioaccumulation | The accumulation of particular chemicals in organisms to a greater concentration than that found in the environmental medium to which the organisms are exposed. For example, the accumulation of copper to levels of 30 ppm in fish exposed to water containing only 1 ppm of copper. |
| biocide | A general name for a chemical used to control biological activity, for example, a BACTERICIDE (q.v.). |
| biota | The collection of living organisms found in a particular region. |
| BPCTCA | Best Practicable Control Technology Currently Achievable; describes an effluent treatment standard which must be set for all industries and met by 1977. (See BATEA) |
| brine | Water containing a high concentration of dissolved salts; frequently used to describe produced waters (q.v.). |
| Btu | British thermal unit; the amount of heat needed to raise the temperature of 1 pound of water 1° F at or near 39.2° F. |
| burning front | The surface bordering the region in which combustion occurs (the burning zone) in in-situ combustion. |

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| carbon dioxide injection | The injection of gaseous carbon dioxide or carbonic acid into an oil reservoir to improve miscibility of oil with injected water and to improve physical properties (viscosity, density) of the oil. |
| caustic flooding | The use of caustics to increase the miscibility of oil with water injected for waterflooding. |
| caustics | Hydroxides of light metals: e.g., sodium hydroxide, NaOH, or potassium hydroxide, KOH. |
| chronic | Describing a toxic effect which is long in onset and duration. |
| CO | Carbon monoxide. |
| coagulants | Chemicals added to wastewaters during treatment in order to cause dispersed suspended particles to aggregate and settle out. |
| coastal baseline | A legal demarcation line dividing the coastal waters of the United States into two regions: onshore and offshore. The baseline is essentially a "smoothed" version of the U.S. coastline, and is used as a reference line for the calculation of the 3-mile limit and other coastline-based demarcations. |
| COFCAW | Combination of Forward Combustion and Waterflooding; a wet combustion process developed by the Amoco Production Company. (For description see Chapter IV, Section C.2.2. of this report.) |
| COHb | Carboxyhemoglobin, a modified form of hemoglobin formed when hemoglobin reacts with carbon monoxide; it is incapable of carrying oxygen as normal hemoglobin does. |
| coke | A solid residue remaining from the destructive (anaerobic) distillation of, e.g., petroleum. |
| connate water | Water which was laid down and entrapped with sedimentary deposits, as distinguished from migratory waters that have flowed into deposits after they were laid down. |
| continental shelf | The gently sloping submerged edge of a continent. |
| cosurfactants | Chemicals used together with surfactants in micellar-polymer operations to control the stability and viscosity of the micellar slug. |

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| cracking | Reduction of the molecular weight of hydrocarbons, particularly petroleum hydrocarbons, through any one of a number of thermal or catalytic methods. |
| CRSTER | A computerized, mathematical model of the dispersion of air pollutants developed by the U.S. Environmental Protection Agency. |
| crude oil | Unrefined oil. |
| deep horizon wells | For purposes of this report, wells drilled deeper than 15,000 feet. |
| dispersion | The movement of pollutants (e.g.) in the environment; e.g., the dispersion of stack gases in the atmosphere, or the dispersion of discharged brines in coastal waters. |
| distillate fuel | Any one of a wide variety of fuels obtained from fractions boiling above the temperature at which gasoline comes off in the distillation of petroleum. |
| divalent cations | Ions with a double positive charge; e.g., the calcium ion, Ca$^{++}$, or the magnesium ion, Mg$^{++}$. |
| effluent | A waste (most commonly a liquid waste) discharged from a particular process. |
| emission factor | A factor expressing the amount of pollutant (generally an atmospheric pollutant) released per unit activity of a particular process; e.g., pounds of SO$_2$ produced per pound of fuel burned by a boiler. |
| emulsification | The formation of a stable dispersion (a emulsion) of one liquid in another liquid with which it is immiscible; e.g., the formation of an oil-water emulsion. |
| emulsion | See EMULSIFICATION. |
| enhanced recovery | Secondary or tertiary recovery techniques. |
| EPA | U.S. Environmental Protection Agency. |
| epidemiological | Pertaining to or making use of data on public health statistics. |
| estuary | The region near the mouth of a river where it enters the ocean; characterized by measurable diluton of seawater with inflowing freshwater. |

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| evaporation ponds | Ponds used to evaporate brines and other liquid wastes to dryiness for subsequent disposal. |
| far offshore | The region of U.S. coastal waters outside of the 3-mile limit. |
| FEA | Federal Energy Administration. |
| field | The surface projection of an oil reservoir; the surface region in which wells can be sunk for the prupose of oil production. |
| fireflooding | In-situ combustion (q.v.). |
| flowing wells | Wells in which the natural pressure of oil in the reservoir is sufficient to raise oil to the surface. |
| flue gas | Gaseous combustion products, such as the process gases produced by in-situ combustion. |
| freewater knockout | Preliminary separation of nonemulsified oil from produced water. |
| gas injection | Injection of gas (generally natural gas) into an oil reservoir to push oil up to the surface through a production well. |
| gas lift | Method of raising oil from the reservoir to the surface by injecting gas into the well below a column of oil. The gas mixes with the oil and expands, lightening the fluid and lifting it to the surface. |
| geometric mean | A type of average of a set of n measurements obtained by taking the nth root of the product of the measurements. |
| HC | Hydrocarbons, generally non-methane hydrocarbons. |
| histopathology | The branch of pathology that deals with tissue changes associated with disease. |
| hypersaline | Having a high salinity or salt concentration. |
| injection | The subsurface emplacement of fluids; the emplacement of fluids underground generally by forced pumping. |
| injection well | A well through which fluids are injected into subsurface formations. |

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| in-situ combustion | The combustion of part of the oil in a reservoir, sustained through the injection of air, in order to create conditions favorable to the production of the non-combusted oil. |
| leaching | The solution of pollutants in water as it percolates down through underground pollution sources such as landfills. |
| lease | In a petroleum law, the right to remove hydrocarbons underlying a particular surface area. |
| MBAS | Methylene blue active substances; surfactants. |
| MCF | One thousand cubic feet (e.g., of a gas). |
| MMCF | One million cubic feet (e.g., of a gas). |
| micellar | Describing a system in which molecules (generally surfactant molecules) aggregate into clumps known as micelles. |
| micellar-polymer technique | A technique in which a surfactant slug is injected into a reservoir together with a polymeric mobility buffer in order to increase the recovery of a waterflood. |
| micellar slug | A liquid mass containing a high concentration of a surfactant. |
| MMBtu | One million Btu's. |
| mobility buffer | A polymeric solution having unusual viscosity properties injected into an oil reservoir following a micellar slug in order to control the movement of the slug through the reservoir and to prevent its dissipation. |
| morbidity | In public health, disease, as opposed to death (mortality). |
| mortality | See MORBIDITY. |
| NAAQS | National Ambient Air Quality Standards, maximum limits set by the Federal government for time average concentrations of particular pollutants in the atmosphere. |
| near offshore | Coastal waters falling inside the 3-mile limit. |

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| nearshore | Coastal waters located inside the so-called coastal baseline; essentially, inland coastal bays and inlets. |
| 96 hr LC50 | A concentration of a particular chemical in a water body which will produce mortality in 50 percent of the resident organisms of a particular species within a period of 96 hours. |
| $NO_x$ | Nitrogen oxides. |
| OCS | Outer Continental Shelf (q.v.). |
| oilfield brine | Produced waters (q.v.). |
| Outer Continental Shelf | That region of the continental shelf beyond the 3-mile limit. |
| oxygen scavenger | Chemicals added to injected waters to consume excess oxygen which might otherwise corrode well casing. |
| paraffins | A saturated, aliphatic (q.v.), straight-chain hydrocarbon; general molecular formula $C_nH_{2n+2}$. |
| particulate | Consisting of or made up of particles. |
| partition coefficient | A parameter describing the affinity of a particular solute for different solvents. |
| photochemical | Describing chemical reactions which are catalyzed by light. |
| photochemical air pollution | A mixture of partially oxidized gaseous hydrocarbons produced by the action of photochemical oxidants (e.g., ozone, nitrogen oxides), on hydrocarbons in the atmosphere. |
| PM | Particulate matter. |
| point source | A source of concentrated emissions of a pollutant; e.g., a smokestack or a pipe discharging liquid wastes into a water body. |
| pore volume | The volume of empty space in an oil reservoir, therefore the maximum volume of fluids which can be stored in the reservoir. |
| ppb | Parts per billion. |
| ppm | Parts per million. |

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| primary oil recovery | Oil recovery through natural pressure or pumping, recovery which takes place without any alteration of natural reservoir conditions. |
| preflush | The first phase of micellar-polymer recovery, in which a brine solution is injected into the formation to (1) provide a tracer analysis of the project flow characteristics, (2) adjust salinity if necessary, and (3) reduce the concentration of divalent ions in the reservoir which may adversely affect the action of the micellar solution. |
| produced fluids | The oil, water, and natural gas which are carried up an oil well from a reservoir. |
| production | The extraction of fluids from an oil reservoir. |
| produced water | Water produced from an oil reservoir and mixed with the produced oil. See OILFIELD BRINE, BRINE. |
| production well | A well through which produced fluids are extracted from an oil reservoir. |
| project | A pilot oil production operation, consisting of a small number (2 to 5) of wells (generally used only for tertiary recovery). |
| receiving water | A water body into which wastes are discharged. |
| reducing bacteria | Bacteria which are capable of chemically transforming oxidized forms of sulfur (such as sulfate) to hydrogen sulfide gas. |
| regression analysis | Statistical analysis designed to determined the magnitude of correlations between two variables. |
| reservoir | A subsurface formation of porous rock, saturated with oil, water, and natural gas, and capped by an impermeable formation. |
| residual fuel oil | Topped crude petroleum of viscous residuums from refinery operations. |
| secondary oil recovery | The injection of water or gas into a reservoir to push oil up through a production well or to maintain reservoir pressure. |
| sequestering agents | Chemicals added to injected water to prevent scale formation in injection wells. |
| sessile | Non-mobile. |

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| sludge | A semi-solid byproduct produced in the treatment of wastewaters, especially municipal sewage wastes. |
| $SO_2$ | Sulfur dioxide. |
| $SO_x$ | Sulfur oxides, sulfate, sulfuric acid, sulfur trioxide, sulfur dioxide. |
| steam distillation | Volatilization of particular components of a liquid mixture through the injection of steam. |
| steam drive | A steam injection process in which the steam is injected continuously throughout the production process. |
| steam injection | The injection of steam into an oil reservoir to decrease the viscosity of oil and drive it towards the production well. |
| steam soak | A steam injection process in which the steam is injected for only a short time at the beginning of the production phase. |
| steamflooding | Steam injection. |
| stripper wells | Wells which produce less than 10 barrels per day. |
| sublethal | Describing a toxic effect which does not result in death. |
| surfactant | Surface active agent; a chemical which reduces the interfacial tension between oil and water, stabilizing oil-water emulsions and increasing the miscibility of oil in water. |
| suspended solids | Particulate matter which does not settle out of the water body or waste stream in which it is found after a brief settling period. |
| sweep efficiency | The ratio of the volume swept out by injected fluid to the volume of a reservoir. |
| synergistic | Describing an interaction between two chemicals in which the combined toxic effect of the two chemicals is greater than the sum of the effects produced if the chemicals are administered separately. See ADDITIVE and ANTAGONISTIC. |
| TDS | Total dissolved solids. |
| tertiary oil recovery | The use of chemical or thermal methods to increase oil recovery from a reservoir. |

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| threshold | A level just below which a certain effect will not be observed. For example, a toxic chemical is said to exhibit threshold behavior if it produces no effects below a certain concentration. |
| TL50 | A concentration of a toxic substance which produces 50 percent mortality in a particular species within a stated time period; generally a 96 hr LC50 (q.v.). |
| turbidity | Absorption and scattering of light by suspended particles in a water body. |
| vertical heater-treater | A device which uses thermal methods to "break" oil-water emulsions and thereby to separate the oil and water phases of the emulsion. |
| UIC | Underground Injection Control (Regulations), promulgated by EPA to protect underground water supplies from contamination by leakage from injection wells. |
| wellhead | The top of the well; e.g., price of oil at the wellhead. |
| wet combustion | The injection of water into a formation heated by in-situ combustion. |
| wettability | As applied to petroleum reservoirs, the relative affinity of the coexisting oil and water phases for the surfaces of pores in the reservoir. If the rock is predominantly in contact with water (rather than oil), it is said to be preferentially water-wet. Similarly, if the rock is predominantly in direct contact with oil, it is said to be oil-wet. |
| wetting | The adhesion of a liquid to the surface of a solid. |
| wetting agent | A substance which increases the affinity of a particular solid for a liquid, hence, a substance which increases wettability. |
| WSF | Water-soluble fraction (q.v.). |
| viscosity | The internal resistance of a liquid to shear forces, and therefore to flow. |
| water drive | Method of production in which water is injected into an oil reservoir to move oil towards and up a production well. |

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| water-soluble fraction | A hydrocarbon mixture formed by mixing oil and water and by separating any residual or emulsified oil from the resulting solution. Consists primarily of the aromatic components of crude oil. |
| water quality criteria | Maximum levels set by the EPA for particular chemicals in ambient waters. |
| waterflooding | The injection of water to enhance oil recovery. |
| well | A vertical, line pipeline drilled from the surface of the ground to a geological formation such as an oil reservoir in order to allow the passage of fluids from the reservoir to the surface. Also used to indicate such pipelines drilled for the purpose of subsurface emplacement of fluids; i.e., injection. |
| well failure | The development of cracks in the casing of a well allowing the leakage of produced or injected fluids. |